SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

NOTICE OF REGULAR MEETING

Board of Directors

NOTICE IS HEREBY GIVEN by the undersigned, as the Acting Executive Director of the Southern California Public Power Authority, that a regular meeting of the Board of Directors is to be held as follows:

Thursday, April 18, 2024

10:00 AM

Southern California Public Power Authority

1160 Nicole Court

Glendora, CA 91740

Any writings or documents provided to the Board of Directors regarding any item on this agenda subsequent to distribution of the agenda packet will be made available for public inspection at SCPPA's Office set forth above, during normal business hours. Members of the public may participate in the meeting in person or via teleconferencing and may also view any documents made available during the meeting, using the following information:

Call	Meeting
Dial: 888-788-0099	Zoom: Join Meeting
Meeting ID: 923 7238 1802	Meeting Materials: Access Here
Passcode: 914368	

SCPPA, upon request, will provide reasonable accommodation to the disabled to ensure equal access to its meetings. To ensure availability, such request should be made 72 hours in advance by contacting the Authority at (626) 793-9364 or administration@scppa.org during business hours.

The following matters are the business to be transacted and considered by the Board of Directors:

1. **NOTICE / AGENDA AND OPPORTUNITY FOR THE PUBLIC TO ADDRESS THE BOARD**
   Members of the public may address the Board at this time on any item on today's agenda or any other item that is within the subject matter jurisdiction of the Board. Comments from members of the public shall be limited to three (3) minutes unless additional time is approved by the Board. Any member of the Board may request that items on the agenda be taken out of order, or that items be added to the agenda pursuant to the provisions of Section 54954.2(b) of the California Government Code.

2. **CLOSED SESSION**
   A. **Conference with Legal Counsel – Anticipated Litigation. Significant Exposure to Litigation Pursuant to Paragraphs d(2) and (e)(2) of Govt. Code §54956.9: One potential case**

3. **LEGAL**
   A. **Report out of Closed Session**

4. **CONSENT CALENDAR**
   All matters listed under the Consent Calendar are considered to be routine and will all be enacted by one motion. There will be no separate discussion of these items prior to the time the Board votes on the motion, unless one or more Board members, staff, or a member of the public requests that specific items be discussed and/or removed for separate discussion or action.

   A. **Minutes of the Board of Directors Meeting**
      - Special Meeting Minutes: March 14, 2024
      - Regular Meeting Minutes: March 21, 2024
   B. **Receive and File:**
      1. Finance Committee Meeting Minutes: March 4, 2024
      2. Monthly Investment Report: February 2024
      3. FY 23-24 Second Quarter Financial Report
      4. SCPPA A&G Budget Comparison Report: January 2024
      5. FY 23-24 Q2 Budget-to-Actual Variance Report
      6. Strategic Priorities Report
      7. Palo Verde Report: February 2024
      8. Magnolia Power Project Operations Report: March 2024
      9. Federal Legislative Report: March 2024
   C. **Resolution 2024-012**
      Correction of Administrative Error in Resolution No. 2024-001 regarding SCPPA's Employee Benefits Policy

5. **APPOINTMENT OF OFFICERS**
   A. **Appointment of Treasurer/ Auditor and Assistant Secretary of the Authority for the period commencing May 1, 2024**

6. **EXECUTIVE DIRECTOR REPORT**
   The Interim Executive Director will provide a report on the activities of the Authority since the last Board Meeting.
   A. **Working Group Update**

7. **CHIEF FINANCIAL & ADMINISTRATIVE OFFICER REPORT**
   A. **Southern Transmission System Renewal Project, Revenue Bonds 2024-1 Resolution 2024-014**
      Authorizing: the issuance Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, the Execution and Delivery of a Third Supplemental Indenture of Trust and a Purchase Contract, the delivery of a preliminary Official Statement, and the execution and delivery of an Official Statement, and certain related actions

Resolution No. 2024-015
Resolution as to the Provision of certain continuing disclosure information with respect to the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

B. **Apex Power Project, Refunding Revenue Bonds, 2024 Series A**
Resolution 2024-016
Authorizing: the issuance of Refunding Bonds for the Apex Power Project, the execution and delivery of: a Third Supplemental Indenture of Trust, Refunding Revenue Bonds, 2024 Series A, and a Purchase Contract, the delivery of a Preliminary Official Statement, the execution and delivery of an Official Statement, and certain related actions.

Resolution No. 2024-017
Resolution as to the Provision of certain continuing disclosure information with respect to Apex Power Project, Refunding Revenue Bonds, 2024 Series A

8. **ASSET MANAGEMENT REPORT**
   A. **FY 23-24 Q2 Budget-to-Actual Variance Report**
   B. **Resolution 2024-018**
   Approval of Revision 1 to the Ameresco Chiquita Landfill Gas Project FY 23/24 Budget
   C. **Resolution 2024- 019**
   Approval of Revision 1 to the Heber 1 Geothermal Project FY 23/24 Budget
   D. **Resolution 2024-020**
   Approval of Eland Solar and Storage Center, Phase 1 Project FY 23/24 Budget

9. **GOVERNMENT AFFAIRS REPORT**
   The Director of Government Affairs will report on regional, state, and/or federal legislative and regulatory activities affecting Southern California public power utilities, including climate change, air quality, wildfire mitigation, renewable energy and traditional energy resources, transportation and building electrification, alternative energy supplies, resource planning, market and utility operations, and joint powers agreements.
   A. **State Regulatory Update**
   B. **State Legislative Update, including Energy Bills and Policy Committee Action**
   C. **Federal Issues Update, including Transformers, Inflation Reduction Act Regulations, and US EPA's Pre-Rulemaking Actions on Emission Regulations for Natural Gas Plants**

10. **BOARD MEMBER COMMENTS**
    A. **Opportunity for Board Members to bring up informational items or request that an item be added to a future Board Agenda.**

11. **ADJOURNMENT**

DocuSigned by:
Randolph R. Krager
40619458107B4D2...
Randolph Krager
Acting Executive Director

On behalf of Michael S. Webster, Executive Director
Southern California Public Power Authority

MINUTES OF THE SPECIAL MEETING OF THE BOARD OF DIRECTORS OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

A special meeting of the Board of Directors was held on ***March 14, 2024,*** *at Southern California Public Power Authority,* 1160 Nicole Court, Glendora, CA 91740.

The meeting was called to order at **9:00 AM** by the First Vice President, Todd Dusenberry. Mr. Dusenberry went through the web conference protocol. Ms. Salpi Ortiz took roll.

The following Board Members (B) or Alternates (A) were present:

Anaheim: Dukku Lee (B)
Azusa: Tikan Singh (B) remote participation
Banning: Jim Steffens (B)
Burbank: Joseph Lillio (B)
Cerritos: Robert Lopez (B)
Colton:
Glendale: Mark Young (B)
IID:
LADWP: Ashkan Nassiri (A)
Pasadena:
Riverside: Todd Corbin (B)
Vernon: Todd Dusenberry (B)

Prior to proceeding with the agenda, Mr. Dusenberry notified the Board of a request by the Board President, Tikan Singh, to attend the meeting remotely under Section (j)(2)() of the Government Code due to just cause. Mr. Singh confirmed there were no other individuals present at his meeting location.

Moved by: Dukku Lee, *Anaheim Public Utilities*
Seconded: Jim Steffens, *Banning Electric Utility*

Ms. Ortiz took a Roll Call vote:

	Yes	*No*	*Present, Not Voting*	*Absent*
Anaheim	*X*			
Azusa	*X*			
Banning	*X*			
Burbank	*X*			

Cerritos	***X***			
Colton				***X***
Glendale	***X***			
IID				***X***
LADWP	***X***			
Pasadena				***X***
Riverside	***X***			
Vernon	***X***			

1. **NOTICE/AGENDA AND OPPORTUNITY FOR THE PUBLIC TO ADDRESS THE BOARD**
   Mr. Dusenberry stated that SCPPA staff has confirmed that the meeting was posted and noticed as required by the Brown Act. He invited comments from the public. There were no public comments.

2. **CLOSED SESSION**

   A. **Public Employment – Executive Director**

   B. **Conference with Labor Negotiator. Agency Representative: Tikan Singh, President. Unrepresented Employee: Executive Director**

   C. **Public Employee Appointment – Interim/ Acting Executive Director**

   D. **Conference with Labor Negotiator. Agency Representative: Tikan Singh, President. Unrepresented Employee: Interim/ Acting Executive Director**

   The Board went into closed session at 8:06 a.m. and resumed to open session at 12:07 p.m.

3. **Report Out of Closed Session**
   Christine Godinez, General Counsel, stated that the Board had no items to report out of closed session.

4. **ADJOURNMENT**
   Mr. Dusenberry adjourned the meeting at 12:10 p.m.

Respectfully Submitted,

____
Randolph Krager

Interim Executive Director

MINUTES OF THE REGULAR MEETING OF THE BOARD OF DIRECTORS OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

A regular meeting of the Board of Directors was held on ***March 21, 2024,*** *at Southern California Public Power Authority*, 1160 Nicole Court, Glendora, CA 91740. *The meeting was called to order at* ***10:00 AM*** *by the First Vice President.*

Ms. Salpi Ortiz took roll.

The following Board Members (B) or Alternates (A) were present:

Anaheim: Dukku Lee (B)
Azusa:
Banning: Jim Steffens (B)
Burbank: Joseph Lillio (B)
Cerritos: Mike O' Grady (A)
Colton: Charles Berry (B)
Glendale: Mark Young (B)
IID:
LADWP: Ashkan Nassiri (A)
Pasadena: Lynne Chaimowitz (A)
Riverside: Todd Corbin (B)
Vernon: Todd Dusenberry (B)

1. **NOTICE/AGENDA AND OPPORTUNITY FOR THE PUBLIC TO ADDRESS THE BOARD**
   Todd Dusenberry, First Vice President, went through the in-person and web conference protocol. He noted that SCPPA staff has confirmed that the meeting was noticed and posted as required under the Brown Act. Michael Webster, Executive Director, went through the emergency safety protocols for the in-person meeting participants. Mr. Dusenberry invited comments from the public. There were no public comments.

2. **CONSENT CALENDAR**
   A. Minutes of the Board of Directors Meeting
   - Special Meeting Minutes: January 31, 2024
   - Special Meeting Minutes (Morning): February 15, 2024
   - Regular Meeting Minutes: February 15, 2024
   - Special Meeting Minutes (Afternoon): February 15, 2024
   - Special Meeting Minutes: March 5, 2024

   B. Receive and File:
   1. CY 2023 Q4 Renewables Operating Report
   2. Finance Committee Meeting Minutes: February 5, 2024
   3. Monthly Investment Report: January 2024

4. SCPPA A&G Budget Comparison Report: January 2024
5. Palo Verde Report: February 2024
6. Magnolia Power Project Operations Report: February 2024
7. Federal Legislative Report: February 2024

Moved by: Dukku Lee, *Anaheim Public Utilities*
Seconded: Charles Berry, *Colton Electric Utility*

Ms. Ortiz took a Roll Call vote:

	Yes	***No***	***Present, Not Voting***	***Absent***
Anaheim	***X***			
Azusa				***X***
Banning	***X***			
Burbank				***X***
Cerritos	***X***			
Colton	***X***			
Glendale	***X***			
IID				***X***
LADWP	***X***			
Pasadena	***X***			
Riverside				***X***
Vernon	***X***			

3. EXECUTIVE DIRECTOR REPORT

A. Working Group Update

Mr. Webster updated the Board on SCPPA's status with the Hoover Lower Colorado River Multispecies Conservation Program (LCR MSCP). As SCPPA is no longer a contractor for Hoover energy, SCPPA will be working with the Members that currently participate through SCPPA to transition the LCR MSCP agreements and permits to the Members directly.

Mr. Webster shared that SCPPA has received a restitution check in the approximate amount of $350,000 related to a criminal matter arising out of collusion between an auditor and a former U.S. Bureau or Reclamation employee pertaining to the Hoover project. Mr. Webster stated that SCPPA finance team will distribute the funds appropriately amongst the affected SCPPA members and other Hoover participants.

Mr. Webster announced an April 2, 2024, virtual training for Members regarding the Solicitation and Contract Management Procedure.

Mr. Webster noted that this would be his last Board meeting before retirement and thanked the Board for the opportunity to lead SCPPA and for having had the opportunity to work with the Board members and Member utilities over the course of his career. The Board Members thanked Mr. Webster for his service.

4. CHIEF FINANCIAL & ADMINISTRATIVE OFFICER REPORT

A. Cost of Living Adjustment

Ms. Aileen Ma, Chief Financial & Administrative Officer, presented to the Board the cost of living adjustment (COLA) setting process from the FY 2023-24 budget, as well as the COLA information collected thus far from the SCPPA Members for the proposed FY 2024-25 budget.

Mr. Dukku Lee, Anaheim Public Utilities, suggested that COLA be determined as discussed a couple of years ago. Members have the option to provide their utility COLA data within a specified deadline, without it being mandatory. He further proposed that SCPPA not re-adjust COLAs in future years based on corrections or adjustments to COLA data previously submitted.

After Board discussion, Mr. Lee moved to calculate SCPPA's COLA based upon the average of the COLAs submitted by those SCPPA Members that responded by a specified deadline. Each Board member has the option to either provide COLA data, or if COLA data is unavailable, to provide SCPPA with a zero COLA, or to choose not to disclose COLA. Ms. Ma stated that she had initially given the Board a deadline of February 12, 2024 to provide COLA data. Mr. Lee also moved to extend the initial deadline for submitting COLA data to SCPPA from February 12, 2024, to March 27, 2024 for the upcoming budget.

Moved by: Dukku Lee, *Anaheim Public Utilities*
Seconded: Todd Corbin, *Riverside Public Utilities*

Ms. Ortiz took a Roll Call vote:

	Yes	*No*	*Present, Not Voting*	*Absent*
Anaheim	*X*			
Azusa				*X*
Banning	*X*			
Burbank	*X*			
Cerritos	*X*			

Colton	***X***			
Glendale	***X***			
IID				***X***
LADWP	***X***			
Pasadena	***X***			
Riverside	***X***			
Vernon	***X***			

B. Resolution 2024-011
Approve Apex Power Project Bond Refunding – Initial Authorizing Resolution

Ms. Ma presented Resolution 2024-011 to the Board for consideration and approval.

Moved by: Ashkan Nassiri, *LADWP*
Seconded: Dukku Lee, *Anaheim Public Utilities*

Ms. Ortiz took a Roll Call vote:

	Yes	***No***	***Present, Not Voting***	***Absent***
Anaheim	***X***			
Azusa				***X***
Banning	***X***			
Burbank	***X***			
Cerritos	***X***			
Colton	***X***			
Glendale	***X***			
IID				***X***
LADWP	***X***			
Pasadena	***X***			
Riverside	***X***			
Vernon	***X***			

5. GOVERNMENT AFFAIRS DIRECTOR'S REPORT

A. State Regulatory Update

Mr. Mario De Bernardo, Government Affairs Director presented a state regulatory update, including regarding a March 19th meeting between Publicly-Owned Utilities and the California Energy Commission.

B. Federal Issues Update

Mr. De Bernardo presented a federal update including a recap on the APPA Rally/SCPPA Fly-In, Direct Pay Regulations, Transformer Supply Chain Issues. Mr. Chris Kearney, SCPPA consultant presented an update on federal issues.

C. State Legislative Update

Mr. De Bernardo presented a state legislative update, including Net Energy Metering (AB 2619, Connolly), pole attachments, and other recently-introduced bills. Mr. De Bernardo concluded his presentation by announcing the SCPPA Policy Staff Tour will be held on July 10-12, 2024, and the theme will be on Transmission, with two days in Southern California and one day in Nevada.

6. CLOSED SESSION

The Board entered Closed Session at 10:51 am and resumed back into the main session at 11:32 am.

A. Public Employment – Executive Director

B. Conference with Labor Negotiator. Agency Representative: Tikan Singh, President. Unrepresented Employee: Executive Director

C. Public Employee Appointment – Interim Executive Director

D. Conference with Labor Negotiator. Agency Representative: Tikan Singh, President. Unrepresented Employee: Interim Executive Director

7. REPORT OUT RE: CLOSED SESSION AND ACTION ITEMS

A. Report out of Closed Session

Regarding Agenda Items 6(A) and 6(B), Ms. Godinez reported that the Board has identified a top candidate for the Executive Director position at SCPPA and has provided direction to SCPPA's President and Vice President on the negotiation of employment contract terms. Ms. Godinez stated that the Board anticipates that it will consider the appointment and consider an Employment Agreement at the Regular Board of Directors meeting scheduled for April 18, 2024.

B. Oral recommendation re proposed changes to salary and/or fringe benefits of Interim Executive Director

Related to Items 6(C) and 6(D), Ms. Godinez presented an oral recommendation regarding the appointment of an Interim Executive Director, and an oral summary of proposed changes to the salary and/or fringe benefits of the Interim Executive Director. Ms. Godinez stated that the Board has proposed selection of Randolph Krager to be Interim Executive

Director until May 1, 2024, such position to be held concurrently with his existing position as SCPPA Project Development Manager. Ms. Godinez stated that the Board will consider and vote on a proposed 10% increase in Mr. Krager's current salary during the time served as Interim Executive Director.

C. Discussion and possible approval of changes to salary and/or fringe benefits of Interim Executive Director

Ms. Godinez presented the above oral summary of the proposed appointment of Interim Executive Director, and the proposed salary and/or fringe benefits of the Interim Executive Director, to the Board for consideration and approval. Mr. Dusenberry asked for any public comments; no public comments were made.

Moved by: Dukku Lee, *Anaheim Public Utilities*
Seconded: Mark Young, *Glendale Water & Power*

Ms. Ortiz took a Roll Call vote:

	Yes	***No***	***Present, Not Voting***	***Absent***
Anaheim	***X***			
Azusa				***X***
Banning	***X***			
Burbank	***X***			
Cerritos	***x***			
Colton	***X***			
Glendale	***X***			
IID				***X***
LADWP	***X***			
Pasadena				***X***
Riverside	***X***			
Vernon	***X***			

8. BOARD OFFICER APPOINTMENTS

A. Appointment of Officers – Assistant Secretary and Treasurer/Auditor of the Authority.

The Board nominated Mr. Randy Krager to serve as SCPPA Treasurer/Auditor, and to serve as an Assistant Secretary of SCPPA (along with Assistant Secretary Peter Huynh), both offices to be held during the time period April 1, 2024 through April 30, 2024.

Moved by: Dukku Lee, *Anaheim Public Utilities*
Seconded: Ashkan Nassiri, *Los Angeles Department of Water and Power*

Ms. Ortiz took a Roll Call vote:

	Yes	*No*	*Present, Not Voting*	*Absent*
Anaheim	*X*			
Azusa				*X*
Banning	*X*			
Burbank	*X*			
Cerritos	*x*			
Colton	*X*			
Glendale	*X*			
IID				*X*
LADWP	*X*			
Pasadena				*X*
Riverside	*X*			
Vernon	*X*			

9. BOARD MEMBER COMMENTS

A. Opportunity for Board Members to bring up informational items or request that an item be added to a future Board Agenda.

Mr. Dusenberry invited Board members to bring up informational items or request that items be added to a future Board Agenda. There were no comments made nor requests to add items.

10. ADJOURNMENT

Mr. Dusenberry adjourned the meeting at 12:36 p.m.

Respectfully Submitted,

Randolph Krager
Interim Executive Director

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
1160 NICOLE COURT
GLENDORA, CA 91740
(626) 793-9364 – FAX: (626) 793-9461
WWW.SCPPA.ORG

MINUTES OF THE REGULAR MEETING OF THE FINANCE COMMITTEE OF SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

The meeting of the Finance Committee was held on **March 4, 2024**, at the SCPPA Glendora office and by teleconference from Imperial Irrigation District. The meeting commenced at 10:30 A.M. and adjourned at 11:52 A.M.

Committee members participating were: Brian Beelner *(Anaheim)*; Daniel Smith *(Azusa)*; Jim Steffens *(Banning)*; Joseph Lillio *(Burbank)*; Ren Zhang *(Colton)*; David Davis *(Glendale)*; Belen Valenzuela (*IID-Teleconference*); Peter Huynh *(LADWP)*; Lynne Chaimowitz *(Pasadena)*; Kristina Bernal (*Riverside*); and Richard Corbi *(Vernon)*

Others attendees were: Stela Kalomian *(Burbank)*; Herman Leung *(Pasadena);* Huitzilo Arriaga *(Pasadena-Teleconference)*; Victor Hsu *(Norton Rose Fulbright*); Mike Berwanger *(PFM Financial Advisors);* Louise Houghton and Jim Carbone (*PFM Financial Advisors-Teleconference*); Grace Mao *(LADWP/SCPPA);* John Equina, Francisco Olivares-Ortiz, and Houbert Yousef (*LADWP/SCPPA-Teleconference);* Mike Webster, Aileen Ma, Charles Guss, Christine Godinez, and Troy Cook *(SCPPA);* and Armando Arballo *(SCPPA-Teleconference)*

1. Opportunity for the Public to Address the Committee

Mr. Corbi (Committee Chair) invited any members of the public to provide comments. No public comments were made.

2. Consent Calendar

Mr. Corbi presented the Consent Calendar to the Committee for consideration. The Committee recommended forwarding the reports to the Board of Directors (Board) for receipt and filing.

A. Minutes of the February 5, 2024 Finance Committee meeting
B. Investment Report for the month ended January 31, 2024
C. Administrative & General Expense (A&G) Budget Comparison Report for the month ended January 31, 2024

Moved By: Dave Davis
Seconded By: Jim Steffens

The following roll call vote was taken:

	Yes	No	Present, Not Voting	Absent
Anaheim	X			
Azusa	X			
Banning	X			
Burbank	X			
Colton	X			
Glendale	X			
IID	X			
LADWP	X			
Pasadena	X			
Riverside	X			
Vernon	X			

3. Energy Prepay

Mr. Berwanger (PFM Financial Advisors) provided the Committee with a status update on the Energy Prepay transaction. Anaheim is targeting to take the transaction to its Board in March and to its City Council in April, with SCPPA consideration to follow.

4. Magnolia Power Project Basis Swap

Mr. Berwanger provided the Committee with an update on the Magnolia Power Project basis swaps. The Committee discussed the four alternatives offered by Barclays Bank PLC (Barclays) to amend the legacy London Interbank Offered Rate (LIBOR) basis swap to Secured Overnight Financing Rate (SOFR) in order to execute a swap suspension. The Committee recommended that SCPPA moves forward with amending the Barclays basis swap to a Daily Weighted SOFR plus a spread of 21.033 basis points, paid semiannually.

Moved By: Joseph Lillio
Seconded By: Lynne Chaimowitz

The following roll call vote was taken:

	Yes	No	Present, Not Voting	Absent
Anaheim	X			
Azusa	X			
Banning	X			
Burbank	X			
Colton	X			
Glendale	X			

IID	X			
LADWP	X			
Pasadena	X			
Riverside	X			
Vernon	X			

5. STS Renewal Project Revenue Bonds

Mr. Berwanger provided the Committee with an update on the financing plan for the issuance of the second tranche of revenue bonds for the STS Renewal Project. The Committee discussed the selection of the investment banking team for the financing. The Committee recommended Barclays Capital as the senior manager and RBC Capital Markets as the co-senior manager, with Seibert Williams Shank, Ramirez & Co., Loop Capital Markets, BofA Securities, and TD Securities as co-managers. Project Vote with LADWP, Burbank, and Glendale as the project participants.

Moved By: Peter Huynh
Seconded By: Joseph Lillio

The following roll call vote was taken:

	Yes	No	Present, Not Voting	Absent
Anaheim	X			
Azusa	X			
Banning	X			
Burbank	X			
Colton	X			
Glendale	X			
IID	X			
LADWP	X			
Pasadena	X			
Riverside	X			
Vernon	X			

6. Apex Power Project Refunding Revenue Bonds

Mr. Berwanger provided the Committee with information on the refinancing of the Apex Power Project, Revenue Bonds, 2014 Series A (Tax-Exempt) and 2014 Series B (Federally Taxable). The Committee recommended a resolution to the Board authorizing the preparation of all necessary documents for the refinancing. Project Vote with LADWP as the sole project participant.

Moved By: Peter Huynh
Seconded By: Brian Beelner

The following roll call vote was taken:

	Yes	No	Present, Not Voting	Absent
Anaheim	X			
Azusa	X			
Banning	X			
Burbank	X			
Colton	X			
Glendale	X			
IID	X			
LADWP	X			
Pasadena	X			
Riverside	X			
Vernon	X			

7. Market and Variable Rate Demand Obligation (VRDO) Update

Mr. Berwanger provided the Committee with a market update and VRDO status report.

8. Unsolicited Proposals

Mr. Berwanger provided the Committee with a summary of the unsolicited proposals that have been received from investment bankers.

9. Pension Funding Update

Ms. Ma provided the Committee with an update on SCPPA's funding level in the California Public Employees' Retirement System (CalPERS) pension plan for Classic and PEPRA Member employees. The Committee would like SCPPA to conduct a survey of the Members on the employee and employer contribution rate structure of the Member agency's retirement plans and provide the results of the survey at a future Finance Committee meeting. Additionally, the Committee would like information regarding potential cost-saving measures for PEPRA Member pension liabilities, focusing on a "Fresh Start" funding option over 10 and 15-year periods.

10. Future Agenda Topics

The Committee members were given the opportunity to suggest topics for future Committee meetings; no new topics were suggested. Mr. Beelner requested consideration of staff reports for SCPPA Finance Committee items.

Ms. Ma announced that with his upcoming retirement, the meeting was Mike Webster's last Finance Committee meeting. She thanked him for his leadership and his dedicated service to SCPPA and the Finance Committee.

THE NEXT REGULARLY SCHEDULED FINANCE COMMITTEE MEETING WILL BE APRIL 1, 2024.

SCPPA
Southern California Public Power Authority
1160 Nicole Court
Glendora, CA 91740
(626) 793-9364

March 22, 2024

Mr. Michael Webster
Executive Director
Southern California Public Power Authority
1160 Nicole Court
Glendora, California 91740

Dear Mr. Webster:

Enclosed is the ***February 2024 Investment Report*** for the Palo Verde, Southern Transmission System (STS), Southern Transmission System Renewal, San Juan, Magnolia Power, Natural Gas, Natural Gas Prepaid, Mead-Adelanto, Mead-Phoenix, Don A. Campbell/Wild Rose Geothermal, Don A. Campbell 2 Geothermal, Canyon Power, Pebble Springs Wind, Tieton Hydropower, MWD Hydro, Linden Wind, Milford Wind I, Milford Wind II, Windy Point/Flats, Ameresco, Apex Power, Copper Mountain Solar 3, Columbia 2 Solar, Heber 1 Geothermal, Ormat No. Nevada Geothermal, Ormesa Geothermal, ARP – Loyalton Biomass, Springbok 1 Solar, Springbok 2 Solar, Springbok 3 Solar, Kingbird Solar, Summer Solar, Astoria 2 Solar, Antelope Big Sky Ranch, Antelope DSR 1, Antelope DSR 2, Puente Hills Landfill Gas, Whitegrass No. 1 Geothermal, Star Peak Geothermal, Desert Harvest II, Roseburg Biomass, Red Cloud Wind, Coso Geothermal, Mammoth Casa Diablo IV, and Daggett Solar Power 2 Projects; and for the Project Stabilization, San Juan Mine Reclamation Trust, San Juan Decommissioning Trust, and the SCPPA Decommissioning Trust Funds. The Portfolios for the Projects and Funds included in the Investment Report are in compliance with the SCPPA Investment Policy.

During the month of February, the Investment Group coordinated variable debt service payments of $450,577 for the Magnolia Power, Linden Wind and Canyon Power Projects. Net swap payments of $432,428 were made in accordance with the Interest Swap agreements for the Canyon Power, Magnolia Power and Natural Gas Prepaid Projects. The net commodity swap receipt for the Natural Gas Prepaid Project was $1,051,100.

$159.8 million of cash and maturities were invested in the various SCPPA project trust funds. Assets managed by the Investment Group for these funds had a market value of $1.2 billion as of February 29, 2024, with an average yield of 4.72%. Total interest earned on the project funds for the month was $6.4 million and year to date was $38.9 million. The escrow funds had a market value of $40.7 million with an average yield of 5.56%. Total interest earned on the escrow funds for the month was $176,104 and year to date was $1.6 million.

Based upon anticipated expenditures for each Project and required receipts from each Participant, SCPPA believes that it will be able to meet all its expenditure requirements for the next six months.

Sincerely,

Grace Mao

GRACE MAO
Manager of Finance
Los Angeles Department of Water & Power

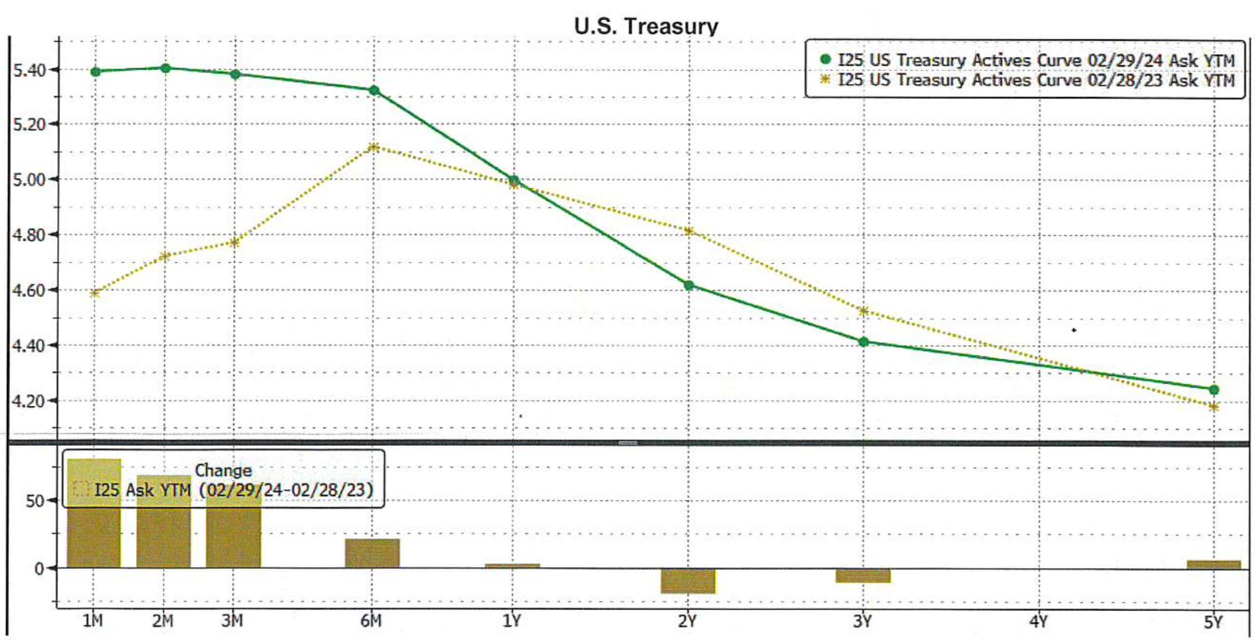
Monthly Investment Report
February 29, 2024

Projects	Portfolio Yield	Investment Cost	Carrying Value	Market Value	Portfolio Life[2]	Cost of Capital[3]
Palo Verde	5.11%	40,380,861	40,645,431	40,582,294	0.18	N/A
San Juan	5.31%	1,774,277	1,778,899	1,778,686	0.08	N/A
Magnolia	5.22%	90,901,429	91,443,320	91,380,798	0.21	2.97%
STS	4.88%	25,389,648	25,540,065	25,482,204	0.31	4.70%
STS Renewal	5.11%	351,589,312	355,811,252	355,790,905	0.47	4.01%
Mead-Phoenix	5.31%	3,863,576	3,876,263	3,876,417	0.05	2.53%
Mead-Adelanto	5.36%	4,463,337	4,492,017	4,492,169	0.09	2.53%
Natural Gas	5.26%	47,765,861	47,823,904	47,796,931	0.26	6.06%
Natural Gas Prepaid[1]	5.10%	20,832,766	20,837,656	20,837,199	9.75	5.09%
Canyon Power	5.37%	18,385,311	18,506,647	18,501,807	0.26	2.74%
Apex Power Project	5.38%	40,549,331	40,868,955	40,864,456	0.22	4.32%
SCPPA Decomm Trust Fund	3.17%	191,115,811	191,261,889	186,141,493	1.32	N/A
Project Stabilization Fund	4.76%	132,509,404	132,938,360	132,243,127	0.46	N/A
Tieton	5.30%	4,396,175	4,415,338	4,415,235	0.18	2.67%
Linden Wind	5.35%	4,953,146	4,969,943	4,969,252	0.04	3.15%
Milford Wind 1	5.42%	19,381,719	19,511,037	19,510,165	0.18	5.08%
Milford Wind 2	5.39%	8,415,870	8,470,550	8,469,839	0.22	1.05%
Windy Point Flats	5.37%	18,792,163	18,870,022	18,867,611	0.16	3.55%
Pwr Purchase Agreements Comb	4.35%	110,299,757	110,937,968	110,930,599	0.06	N/A
San Juan Reclaim Trust Fund	4.52%	20,943,447	21,034,872	20,872,523	0.36	N/A
San Juan Decomm Trust Fund	5.18%	4,812,498	4,843,680	4,837,114	0.38	N/A

[1] *Weighted average remaining portfolio life for NG Prepaid includes GICs with AGL.*

[2] *In years*

[3] *Cost of capital as of January 31, 2024 as provided by PFM.*



Tenor	I25 Ask YTM US Treasury Actives Curve 02/29/24	I25 Ask YTM US Treasury Actives Curve 02/28/23	I25 Ask YTM (Change) 02/29/24-02/28/23
1M	5.390	4.588	80.20
2M	5.402	4.723	68.00
3M	5.380	4.769	61.10
6M	5.321	5.119	20.30
1Y	4.998	4.977	2.10
2Y	4.619	4.816	-19.70
3Y	4.415	4.526	-11.20
5Y	4.245	4.182	6.30

Southern California Public Power Authority

Combined Financial Statements

December 31, 2023 and 2022

(Unaudited)

Southern California Public Power Authority
Combined Financial Statements (Unaudited)
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Southern California Public Power Authority

Combined Financial Statements for the Quarter Ending December 31, 2023

The Authority's net position increased by $123 million mainly due to an increase in assets and deferred outflows of resources of $683 million and an increase in liabilities and deferred inflows of resources of $560 million.

Assets and deferred outflows of resources increased primarily due to:

- Construction costs incurred in the Southern Transmission System Renewal (STSR) Project and ongoing capital expenditures in Palo Verde and Apex Projects,
- The increase in investments, cash and cash equivalents from the issuance of the STSR 2023-1 and 2023-1A Revenue Bonds;

The increase was partially offset by the scheduled depreciation in the generation and transmission projects and scheduled depletion in the Natural Gas Reserve projects, and the scheduled amortization of prepaid assets in Windy Point/Windy Flats, Milford I and II, and Prepaid Natural Gas projects.

Liabilities and deferred inflows of resources increased primarily due to:

- The increase in long-term debt due to the issuance of the STSR 2023-1 and 2023-1A Revenue Bonds,
- The increase in accounts payable due to the accrued liabilities in STSR project, advances from participants in San Juan and Linden projects, and overbillings in various projects;

The increase was partially offset by the release of funds held back in the Windy Point/Windy Flats Project for the 2023-1 refunding.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Summary of Financial Condition and Changes in Net Position
Combined All Projects
(Amounts in Thousands)

	DECEMBER 2023	DECEMBER 2022
Assets		
Net utility plant	$ 1,435,974	$ 1,166,882
Net lease asset	6,974	7,511
Investments	1,015,588	621,964
Cash and cash equivalents	291,259	217,171
Prepaid and other assets	548,868	600,289
Total assets	3,298,663	2,613,817
Deferred ouflows of resources	81,391	82,924
Total assets and deferred outflows of resources	3,380,054	2,696,741
Liabilities		
Noncurrent liabilities		
Long-term debt	$ 2,240,134	$ 1,713,300
Fair value of derivative instruments	5,732	7,050
Long-term lease liabilities	7,392	7,805
Notes payable, other and net pension liabilities	2,930	1,836
Advances from participants	12,243	12,376
Reclamation and decommissioning obligation	241,159	238,781
Total noncurrent liabilities	2,509,590	1,981,148
Current liabilities		
Debt due within one year	156,605	152,005
Current portion of long-term lease liabilities	256	231
Notes payable and other liabilities due within one year	26,294	17,010
Advances from participants due within one year	95,567	133,660
Accrued interest	43,826	33,850
Accounts payable and accruals	210,641	171,723
Total current liabilities	533,189	508,479
Deferred inflows of resources	18,356	11,427
Total liabilities and deferred inflows of resources	3,061,135	2,501,054
Net position		
Net investment in capital assets	(263,696)	75,304
Restricted	634,354	248,290
Unrestricted	(51,739)	(127,907)
Total net position	318,919	195,687
Total liabilities, deferred inflows of resources, and net position	$ 3,380,054	$ 2,696,741
Revenues, Expenses and Changes in net position		
Operating revenues	$ 576,846	$ 653,112
Operating expenses	(489,056)	(607,131)
Operating income	87,790	45,981
Investment and other income	23,312	4,283
Derivative gain (loss)	2,850	2,869
Other interest and debt expense	(28,193)	(28,744)
Net non operating revenues (expenses)	(2,031)	(21,592)
Change in net position	85,759	24,389
Net position - beginning of year	226,748	164,293
Net contribution/(distributions) by participants	6,412	7,005
Net position - end of period	$ 318,919	$ 195,687

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
ASSETS					
Noncurrent assets					
Net utility plant	$ 241,208	$ -	$ 121,535	$ 172,307	$ 229,476
Net lease asset	-	-	3,186	1,704	-
Investments - restricted	201,881	26,768	56,527	11,081	19,665
Investments - unrestricted	5,468	-	18,786	-	5,519
Advance to IPA - restricted	-	-	-	-	-
Prepaid and other assets	-	-	-	-	-
Total noncurrent assets	448,557	26,768	200,034	185,092	254,660
Current assets					
Cash and cash equivalents - restricted	4,752	-	8,967	3,869	7,251
Cash and cash equivalents - unrestricted	9,715	1,110	3,625	4,088	10,393
Interest receivable	1,641	225	476	47	37
Accounts receivable	3,917	-	795	148	-
Materials and supplies	12,317	-	11,572	806	6,001
Prepaid and other assets	579	36	334	29	5,142
Total current assets	32,921	1,371	25,769	8,987	28,824
DEFERRED OUTFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized loss on refunding	-	-	9,100	20,462	-
Reclamation and decommissioning obligation	30,561	-	-	-	5,590
Accumulated decrease in fair value of hedging derivatives	-	-	5,627	466	-
Total deferred outflows of resources	30,561	-	14,727	20,928	5,590
Total assets and deferred outflows of resources	$ 512,039	$ 28,139	$ 240,530	$ 215,007	$ 289,074
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ -	$ -	$ 221,757	$ 248,395	$ 226,553
Fair value of derivative instruments	-	-	1,677	466	-
Long-term lease liabilities	-	-	3,292	1,807	-
Notes payable, other and net pension liabilities	-	-	-	-	-
Advances from participants	-	-	-	-	-
Reclamation and decommissioning obligation	204,928	20,524	-	-	11,832
Total noncurrent liabilities	204,928	20,524	226,726	250,668	238,385
Current Liabilities					
Debt due within one year	-	-	11,325	13,560	11,205
Current portion of long-term lease liabilities	-	-	118	38	-
Notes payable and other liabilities due within one year	-	-	26,294	-	-
Advances from participants due within one year	-	5,958	21,655	3,716	23,458
Accrued interest	-	-	4,899	1,980	5,370
Accounts payable and accruals	7,984	779	5,976	6,044	10,521
Accrued property taxes	1,830	-	-	-	-
Total current liabilities	9,814	6,737	70,267	25,338	50,554
Total liabilities	214,742	27,261	296,993	276,006	288,939
DEFERRED INFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized gain on refunding	-	-	-	-	-
Regulatory liability	-	-	-	-	-
Total deferred inflows of resources	-	-	-	-	-
NET POSITION			-		-
Net investment in capital assets	241,208	-	(102,672)	(69,326)	(1,622)
Restricted	33,827	(160)	24,560	9,289	(14,790)
Unrestricted	22,262	1,038	21,649	(962)	16,547
Total net position	297,297	878	(56,463)	(60,999)	135
Total liabilities, deferred inflows of resources, and net position	$ 512,039	$ 28,139	$ 240,530	$ 215,007	$ 289,074

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
ASSETS					
Noncurrent assets					
Net utility plant	$ 248,848	$ -	$ 131,115	$ 181,752	$ 240,803
Net lease asset	-	-	3,452	1,814	-
Investments - restricted	195,264	24,873	41,055	15,812	18,451
Investments - unrestricted	8,485	-	11,961	-	-
Advance to IPA - restricted	-	-	-	-	-
Prepaid and other assets	-	-	-	-	-
Total noncurrent assets	452,597	24,873	187,583	199,378	259,254
Current assets					
Cash and cash equivalents - restricted	5,103	-	14,887	2,076	7,307
Cash and cash equivalents - unrestricted	10,739	170	10,290	634	12,177
Interest receivable	365	126	263	37	29
Accounts receivable	1,527	13	407	113	191
Materials and supplies	12,128	-	11,504	806	6,006
Prepaid and other assets	561	20	56	21	1,166
Total current assets	30,423	329	37,407	3,687	26,876
DEFERRED OUTFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized loss on refunding	-	-	10,419	22,330	-
Reclamation and decommissioning obligation	31,913	-	-	-	5,956
Accumulated decrease in fair value of hedging derivatives	-	-	691	-	-
Total deferred outflows of resources	31,913	-	11,110	22,330	5,956
Total assets and deferred outflows of resources	$ 514,933	$ 25,202	$ 236,100	$ 225,395	$ 292,086
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ -	$ -	$ 235,141	$ 262,919	$ 238,505
Fair value of derivative instruments	-	-	2,596	616	-
Long-term lease liabilities	-	-	3,529	1,883	-
Notes payable, other and net pension liabilities	-	-	-	-	-
Advances from participants	-	-	-	-	-
Reclamation and decommissioning obligation	199,019	24,508	-	-	11,491
Total noncurrent liabilities	199,019	24,508	241,266	265,418	249,996
Current Liabilities					
Debt due within one year	-	-	10,760	13,245	10,830
Current portion of long-term lease liabilities	-	-	112	36	-
Notes payable and other liabilities due within one year	-	-	17,010	-	-
Advances from participants due within one year	-	-	21,293	7,473	22,462
Accrued interest	-	-	4,437	2,036	5,558
Accounts payable and accruals	11,724	404	4,225	1,970	3,074
Accrued property taxes	1,830	-	-	-	-
Total current liabilities	13,554	404	57,837	24,760	41,924
Total liabilities	212,573	24,912	299,103	290,178	291,920
DEFERRED INFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized gain on refunding	-	-	-	-	-
Total deferred inflows of resources	-	-	-	-	-
NET POSITION					
Net investment in capital assets	248,847	-	(104,556)	(72,802)	(1,226)
Restricted	33,598	220	24,937	8,413	(14,434)
Unrestricted	19,915	70	16,616	(394)	15,826
Total net position	302,360	290	(63,003)	(64,783)	166
Total liabilities, deferred inflows of resources, and net position	$ 514,933	$ 25,202	$ 236,100	$ 225,395	$ 292,086

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
ASSETS					
Noncurrent assets					
Net utility plant	$ 28,752	$ -	$ -	$ -	$ 69,240
Net lease asset	-	-	-	-	2,084
Investments - restricted	2,280	15,165	4,439	3,437	3,626
Investments - unrestricted	-	-	-	-	-
Advance to IPA - restricted	-	-	-	-	-
Prepaid and other assets	-	62,820	62,314	169,890	-
Total noncurrent assets	31,032	77,985	66,753	173,327	74,950
Current assets					
Cash and cash equivalents - restricted	1,228	2,638	28	2,487	9,110
Cash and cash equivalents - unrestricted	1,040	3,356	4,420	7,712	3,658
Interest receivable	10	34	12	20	22
Accounts receivable	-	-	-	-	909
Materials and supplies	-	-	-	-	-
Prepaid and other assets	253	5,843	4,351	13,737	29
Total current assets	2,531	11,871	8,811	23,956	13,728
DEFERRED OUTFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized loss on refunding	-	-	-	-	-
Reclamation and decommissioning obligation	376	-	-	-	269
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-
Total deferred outflows of resources	376	-	-	-	269
Total assets and deferred outflows of resources	$ 33,939	$ 89,856	$ 75,564	$ 197,283	$ 88,947
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ 34,376	$ 73,197	$ 70,387	$ 157,314	$ 41,901
Fair value of derivative instruments	-	-	-	-	-
Long-term lease liabilities	-	-	-	-	2,293
Notes payable, other and net pension liabilities	-	-	-	-	-
Advances from participants	-	-	-	-	-
Reclamation and decommissioning obligation	1,017	-	-	-	832
Total noncurrent liabilities	35,393	73,197	70,387	157,314	45,026
Current Liabilities					
Debt due within one year	1,300	11,115	6,950	13,340	40,320
Current portion of long-term lease liabilities	-	-	-	-	100
Notes payable and other liabilities due within one year	-	-	-	-	-
Advances from participants due within one year	202	2,770	250	1,000	10,724
Accrued interest	752	1,891	1,660	1,056	2,238
Accounts payable and accruals	933	8,007	2,212	6,702	1,091
Accrued property taxes	-	-	-	377	146
Total current liabilities	3,187	23,783	11,072	22,475	54,619
Total liabilities	38,580	96,980	81,459	179,789	99,645
DEFERRED INFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized gain on refunding	462	869	1,589	14,913	-
Regulatory liability	-	-	-	-	-
Total deferred inflows of resources	462	869	1,589	14,913	-
NET POSITION					
Net investment in capital assets	(6,924)	-	-	-	(13,289)
Restricted	1,663	-	-	-	10,361
Unrestricted	158	(7,993)	(7,484)	2,581	(7,770)
Total net position	(5,103)	(7,993)	(7,484)	2,581	(10,698)
Total liabilities, deferred inflows of resources, and net position	$ 33,939	$ 89,856	$ 75,564	$ 197,283	$ 88,947

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
ASSETS					
Noncurrent assets					
Net utility plant	$ 30,254	$ -	$ -	$ -	$ 75,054
Net lease asset	-	-	-	-	2,245
Investments - restricted	1,939	9,346	5,016	51,161	11,578
Investments - unrestricted	-	-	410	-	-
Advance to IPA - restricted	-	-	-	-	-
Prepaid and other assets	-	74,497	71,011	197,340	-
Total noncurrent assets	32,193	83,843	76,437	248,501	88,877
Current assets					
Cash and cash equivalents - restricted	1,548	3,366	157	3,542	1,413
Cash and cash equivalents - unrestricted	876	4,976	2,820	8,877	1,779
Interest receivable	4	41	4	198	33
Accounts receivable	-	-	-	-	1,055
Materials and supplies	-	-	-	-	-
Prepaid and other assets	163	5,845	4,352	13,739	27
Total current assets	2,591	14,228	7,333	26,356	4,307
DEFERRED OUTFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized loss on refunding	-	-	-	-	-
Reclamation and decommissioning obligation	399	-	-	-	292
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-
Total deferred outflows of resources	399	-	-	-	292
Total assets and deferred outflows of resources	$ 35,183	$ 98,071	$ 83,770	$ 274,857	$ 93,476
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ 36,260	$ 87,341	$ 80,193	$ 253,187	$ 83,714
Fair value of derivative instruments	-	-	-	-	-
Long-term lease liabilities	-	-	-	-	2,393
Notes payable, other and net pension liabilities	-	-	-	-	-
Advances from participants	-	-	-	-	-
Reclamation and decommissioning obligation	987	-	-	-	808
Total noncurrent liabilities	37,247	87,341	80,193	253,187	86,915
Current Liabilities					
Debt due within one year	1,225	10,590	6,620	12,265	4,735
Current portion of long-term lease liabilities	-	-	-	-	83
Notes payable and other liabilities due within one year	-	-	-	-	-
Advances from participants due within one year	202	2,770	250	45,897	10,213
Accrued interest	788	2,155	1,825	6,246	2,356
Accounts payable and accruals	678	4,656	1,754	5,025	412
Accrued property taxes	-	-	-	437	274
Total current liabilities	2,893	20,171	10,449	69,870	18,073
Total liabilities	40,140	107,512	90,642	323,057	104,988
DEFERRED INFLOWS OF RESOURCES					
Deferred items related to pensions	-	-	-	-	-
Unamortized gain on refunding	506	1,433	2,055	6,586	119
Total deferred inflows of resources	506	1,433	2,055	6,586	119
NET POSITION					
Net investment in capital assets	(7,231)	-	-	-	(13,625)
Restricted	1,609	-	-	-	10,844
Unrestricted	159	(10,874)	(8,927)	(54,786)	(8,850)
Total net position	(5,463)	(10,874)	(8,927)	(54,786)	(11,631)
Total liabilities, deferred inflows of resources, and net position	$ 35,183	$ 98,071	$ 83,770	$ 274,857	$ 93,476

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	TRANSMISSION			
	Southern Transmission System Project	Southern Transmission System Renewal Project	Mead-Phoenix Project	Mead-Adelanto Project
ASSETS				
Noncurrent assets				
Net utility plant	$ 89,972	$ 329,389	$ 35,109	$ 71,590
Net lease asset	-	-	-	-
Investments - restricted	17,806	434,290	1,038	1,700
Investments - unrestricted	-	-	-	-
Advance to IPA - restricted	10,930	10,131	-	-
Prepaid and other assets	-	-	-	-
Total noncurrent assets	118,708	773,810	36,147	73,290
Current assets				
Cash and cash equivalents - restricted	4,510	53,628	1,848	1,483
Cash and cash equivalents - unrestricted	653	-	1,560	1,275
Interest receivable	59	2,439	12	9
Accounts receivable	6,389	49	-	96
Materials and supplies	-	-	-	-
Prepaid and other assets	24	-	43	61
Total current assets	11,635	56,116	3,463	2,924
DEFERRED OUTFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized loss on refunding	3,976	-	-	-
Reclamation and decommissioning obligation	-	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-	-
Total deferred outflows of resources	3,976	-	-	-
Total assets and deferred outflows of resources	$ 134,319	$ 829,926	$ 39,610	$ 76,214
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ 93,898	$ 782,055	$ 12,457	$ 15,341
Fair value of derivative instruments	-	-	-	-
Long-term lease liabilities	-	-	-	-
Notes payable, other and net pension liabilities	-	-	-	-
Advances from participants	-	-	-	-
Reclamation and decommissioning obligation	-	-	-	-
Total noncurrent liabilities	93,898	782,055	12,457	15,341
Current Liabilities				
Debt due within one year	27,055	-	1,595	1,965
Current portion of long-term lease liabilities	-	-	-	-
Notes payable and other liabilities due within one year	-	-	-	-
Advances from participants due within one year	-	-	504	702
Accrued interest	2,850	17,397	324	400
Accounts payable and accruals	7,035	30,122	2,103	897
Accrued property taxes	-	-	-	-
Total current liabilities	36,940	47,519	4,526	3,964
Total liabilities	130,838	829,574	16,983	19,305
DEFERRED INFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized gain on refunding	-	-	-	-
Regulatory liability	-	352	-	-
Total deferred inflows of resources	-	352	-	-
NET POSITION				
Net investment in capital assets	(27,005)	(396,599)	21,056	54,284
Restricted	30,455	396,599	2,573	2,087
Unrestricted	31	-	(1,002)	538
Total net position	3,481	-	22,627	56,909
Total liabilities, deferred inflows of resources, and net position	$ 134,319	$ 829,926	$ 39,610	$ 76,214

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	TRANSMISSION		
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project
ASSETS			
Noncurrent assets			
Net utility plant	$ 94,018	$ 37,522	$ 77,980
Net lease asset	-	-	-
Investments - restricted	40,935	1,217	1,135
Investments - unrestricted	-	-	-
Advance to IPA - restricted	10,930	-	-
Prepaid and other assets	-	-	-
Total noncurrent assets	145,883	38,739	79,115
Current assets			
Cash and cash equivalents - restricted	6,734	1,226	1,443
Cash and cash equivalents - unrestricted	436	1,877	2,227
Interest receivable	58	7	5
Accounts receivable	7,497	-	-
Materials and supplies	-	-	-
Prepaid and other assets	32	101	1,235
Total current assets	14,757	3,211	4,910
DEFERRED OUTFLOWS OF RESOURCES			
Deferred items related to pensions	-	-	-
Unamortized loss on refunding	6,187	-	-
Reclamation and decommissioning obligation	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-
Total deferred outflows of resources	6,187	-	-
Total assets and deferred outflows of resources	$ 166,827	$ 41,950	$ 84,025
LIABILITIES			
Noncurrent liabilities			
Long-term debt	$ 124,329	$ 14,404	$ 17,748
Fair value of derivative instruments	-	-	-
Long-term lease liabilities	-	-	-
Notes payable, other and net pension liabilities	-	-	-
Advances from participants	-	-	-
Reclamation and decommissioning obligation	-	-	-
Total noncurrent liabilities	124,329	14,404	17,748
Current Liabilities			
Debt due within one year	62,825	1,535	1,870
Current portion of long-term lease liabilities	-	-	-
Notes payable and other liabilities due within one year	-	-	-
Advances from participants due within one year	-	-	-
Accrued interest	4,420	355	446
Accounts payable and accruals	13,821	2,555	3,812
Accrued property taxes	-	-	-
Total current liabilities	81,066	4,445	6,128
Total liabilities	205,395	18,849	23,876
DEFERRED INFLOWS OF RESOURCES			
Deferred items related to pensions	-	-	-
Unamortized gain on refunding	-	-	-
Total deferred inflows of resources	-	-	-
NET POSITION			
Net investment in capital assets	(86,949)	21,584	58,362
Restricted	52,238	2,094	1,682
Unrestricted	(3,857)	(577)	105
Total net position	(38,568)	23,101	60,149
Total liabilities, deferred inflows of resources, and net position	$ 166,827	$ 41,950	$ 84,025

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
ASSETS				
Noncurrent assets				
Net utility plant	$ 19,579	$ 22,078	$ -	$ -
Net lease asset	-	-	-	-
Investments - restricted	-	34,383	11,488	-
Investments - unrestricted	-	-	-	38,026
Advance to IPA - restricted	-	-	-	-
Prepaid and other assets	126	-	135,668	-
Total noncurrent assets	19,705	56,461	147,156	38,026
Current assets				
Cash and cash equivalents - restricted	2,717	5,114	4,846	27
Cash and cash equivalents - unrestricted	3,257	2,111	975	88,010
Interest receivable	14	401	71	162
Accounts receivable	1,926	532	1,753	6,018
Materials and supplies	-	-	-	-
Prepaid and other assets	511	2	6,030	151
Total current assets	8,425	8,160	13,675	94,368
DEFERRED OUTFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized loss on refunding	-	-	-	-
Reclamation and decommissioning obligation	325	77	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	3,589	-
Total deferred outflows of resources	325	77	3,589	-
Total assets and deferred outflows of resources	$ 28,455	$ 64,698	$ 164,420	$ 132,394
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ 8,097	$ 19,068	$ 235,338	$ -
Fair value of derivative instruments	-	-	3,589	-
Long-term lease liabilities	-	-	-	-
Notes payable, other and net pension liabilities	-	-	-	-
Advances from participants	8,467	3,776	-	-
Reclamation and decommissioning obligation	1,672	354	-	-
Total noncurrent liabilities	18,236	23,198	238,927	-
Current Liabilities				
Debt due within one year	1,201	2,824	12,850	-
Current portion of long-term lease liabilities	-	-	-	-
Notes payable and other liabilities due within one year	-	-	-	-
Advances from participants due within one year	1,776	741	-	22,111
Accrued interest	274	647	2,088	-
Accounts payable and accruals	3,408	2,106	2,516	109,580
Accrued property taxes	272	-	-	-
Total current liabilities	6,931	6,318	17,454	131,691
Total liabilities	25,167	29,516	256,381	131,691
DEFERRED INFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized gain on refunding	-	-	-	-
Regulatory liability	-	-	-	-
Total deferred inflows of resources	-	-	-	-
NET POSITION				
Net investment in capital assets	1,401	30,053	-	-
Restricted	377	4,585	-	-
Unrestricted	1,510	544	(91,961)	703
Total net position	3,288	35,182	(91,961)	703
Total liabilities, deferred inflows of resources, and net position	$ 28,455	$ 64,698	$ 164,420	$ 132,394

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
ASSETS				
Noncurrent assets				
Net utility plant	$ 20,892	$ 22,735	$ -	$ -
Net lease asset	-	-	-	-
Investments - restricted	-	35,866	11,376	-
Investments - unrestricted	-	-	-	35,249
Advance to IPA - restricted	-	-	-	-
Prepaid and other assets	126	-	148,358	-
Total noncurrent assets	21,018	58,601	159,734	35,249
Current assets				
Cash and cash equivalents - restricted	2,679	3,496	4,632	32
Cash and cash equivalents - unrestricted	1,837	1,657	531	75,920
Interest receivable	13	113	61	138
Accounts receivable	2,520	779	3,152	14,532
Materials and supplies	-	-	-	-
Prepaid and other assets	510	2	5,952	164
Total current assets	7,559	6,047	14,328	90,786
DEFERRED OUTFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized loss on refunding	-	-	-	-
Reclamation and decommissioning obligation	363	85	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	3,838	-
Total deferred outflows of resources	363	85	3,838	-
Total assets and deferred outflows of resources	$ 28,940	$ 64,733	$ 177,900	$ 126,035
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ 9,299	$ 21,891	$ 248,369	$ -
Fair value of derivative instruments	-	-	3,838	-
Long-term lease liabilities	-	-	-	-
Notes payable, other and net pension liabilities	-	-	-	-
Advances from participants	8,834	3,542	-	-
Reclamation and decommissioning obligation	1,624	344	-	-
Total noncurrent liabilities	19,757	25,777	252,207	-
Current Liabilities				
Debt due within one year	1,270	2,985	11,250	-
Current portion of long-term lease liabilities	-	-	-	-
Notes payable and other liabilities due within one year	-	-	-	-
Advances from participants due within one year	945	1,911	-	20,244
Accrued interest	310	731	2,187	-
Accounts payable and accruals	2,888	2,382	3,555	105,356
Accrued property taxes	891	-	-	-
Total current liabilities	6,304	8,009	16,992	125,600
Total liabilities	26,061	33,786	269,199	125,600
DEFERRED INFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	-	-
Unamortized gain on refunding	-	-	-	-
Total deferred inflows of resources	-	-	-	-
NET POSITION				
Net investment in capital assets	851	26,140	-	-
Restricted	1,446	4,745	-	-
Unrestricted	582	62	(91,299)	435
Total net position	2,879	30,947	(91,299)	435
Total liabilities, deferred inflows of resources, and net position	$ 28,940	$ 64,733	$ 177,900	$ 126,035

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Project Stabilization Fund	SCPPA Fund	**Total Combined**
ASSETS				
Noncurrent assets				
Net utility plant	$ -	$ -	$ 5,739	$ 1,435,974
Net lease asset	-	-	-	6,974
Investments - restricted	-	102,215	-	947,789
Investments - unrestricted	-	-	-	67,799
Advance to IPA - restricted	-	-	-	21,061
Prepaid and other assets	-	-	-	430,818
Total noncurrent assets	-	102,215	5,739	2,910,415
Current assets				
Cash and cash equivalents - restricted	-	29,798	-	144,301
Cash and cash equivalents - unrestricted	-	-	-	146,958
Interest receivable	-	915	-	6,606
Accounts receivable	-	-	-	22,532
Materials and supplies	-	-	-	30,696
Prepaid and other assets	-	-	-	37,155
Total current assets	-	30,713	-	388,248
DEFERRED OUTFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	973	973
Unamortized loss on refunding	-	-	-	33,538
Reclamation and decommissioning obligation	-	-	-	37,198
Accumulated decrease in fair value of hedging derivatives	-	-	-	9,682
Total deferred outflows of resources	-	-	973	81,391
Total assets and deferred outflows of resources	$ -	$ 132,928	$ 6,712	$ 3,380,054
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ -	$ -	$ -	$ 2,240,134
Fair value of derivative instruments	-	-	-	5,732
Long-term lease liabilities	-	-	-	7,392
Notes payable, other and net pension liabilities	-	-	2,930	2,930
Advances from participants	-	-	-	12,243
Reclamation and decommissioning obligation	-	-	-	241,159
Total noncurrent liabilities	-	-	2,930	2,509,590
Current Liabilities				
Debt due within one year	-	-	-	156,605
Current portion of long-term lease liabilities	-	-	-	256
Notes payable and other liabilities due within one year	-	-	-	26,294
Advances from participants due within one year	-	-	-	95,567
Accrued interest	-	-	-	43,826
Accounts payable and accruals	-	-	-	208,016
Accrued property taxes	-	-	-	2,625
Total current liabilities	-	-	-	533,189
Total liabilities	-	-	2,930	3,042,779
DEFERRED INFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	171	171
Unamortized gain on refunding	-	-	-	17,833
Regulatory liability	-	-	-	352
Total deferred inflows of resources	-	-	171	18,356
NET POSITION				
Net investment in capital assets	-	-	5,739	(263,696)
Restricted	-	132,928	-	634,354
Unrestricted	-	-	(2,128)	(51,739)
Total net position	-	132,928	3,611	318,919
Total liabilities, deferred inflows of resources, and net position	$ -	$ 132,928	$ 6,712	$ 3,380,054

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Project Stabilization Fund	SCPPA Fund	**Total Combined**
ASSETS				
Noncurrent assets				
Net utility plant	$ -	$ -	$ 5,909	$ 1,166,882
Net lease asset	-	-	-	7,511
Investments - restricted	-	100,835	-	565,859
Investments - unrestricted	-	-	-	56,105
Advance to IPA - restricted	-	-	-	10,930
Prepaid and other assets	-	-	-	491,332
Total noncurrent assets	-	100,835	5,909	2,298,619
Current assets				
Cash and cash equivalents - restricted	-	19,707	-	79,348
Cash and cash equivalents - unrestricted	-	-	-	137,823
Interest receivable	-	356	-	1,851
Accounts receivable	-	-	-	31,786
Materials and supplies	-	-	-	30,444
Prepaid and other assets	-	-	-	33,946
Total current assets	-	20,063	-	315,198
DEFERRED OUTFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	451	451
Unamortized loss on refunding	-	-	-	38,936
Reclamation and decommissioning obligation	-	-	-	39,008
Accumulated decrease in fair value of hedging derivatives	-	-	-	4,529
Total deferred outflows of resources	-	-	451	82,924
Total assets and deferred outflows of resources	$ -	$ 120,898	$ 6,360	$ 2,696,741
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ -	$ -	$ -	$ 1,713,300
Fair value of derivative instruments	-	-	-	7,050
Long-term lease liabilities	-	-	-	7,805
Notes payable, other and net pension liabilities	-	-	1,836	1,836
Advances from participants	-	-	-	12,376
Reclamation and decommissioning obligation	-	-	-	238,781
Total noncurrent liabilities	-	-	1,836	1,981,148
Current Liabilities				
Debt due within one year	-	-	-	152,005
Current portion of long-term lease liabilities	-	-	-	231
Notes payable and other liabilities due within one year	-	-	-	17,010
Advances from participants due within one year	-	-	-	133,660
Accrued interest	-	-	-	33,850
Accounts payable and accruals	-	-	-	168,291
Accrued property taxes	-	-	-	3,432
Total current liabilities	-	-	-	508,479
Total liabilities	-	-	1,836	2,489,627
DEFERRED INFLOWS OF RESOURCES				
Deferred items related to pensions	-	-	728	728
Unamortized gain on refunding	-	-	-	10,699
Total deferred inflows of resources	-	-	728	11,427
NET POSITION				
Net investment in capital assets	-	-	5,909	75,304
Restricted	-	120,898	-	248,290
Unrestricted	-	-	(2,113)	(127,907)
Total net position	-	120,898	3,796	195,687
Total liabilities, deferred inflows of resources, and net position	$ -	$ 120,898	$ 6,360	$ 2,696,741

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal years ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
Operating revenues					
Sales of electric energy	$ 33,997	$ 96	$ 57,306	$ 18,063	$ 68,997
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	33,997	96	57,306	18,063	68,997
Operating expenses					
Operations and maintenance	21,681	115	48,926	9,199	56,164
Depreciation, depletion and amortization	11,411	-	4,737	4,705	8,560
Amortization of nuclear fuel	5,732	-	-	-	-
Decommissioning	676	-	-	-	183
Total operating expenses	39,500	115	53,663	13,904	64,907
Operating income (loss)	(5,503)	(19)	3,643	4,159	4,090
Non operating revenues (expenses)					
Investment and other income	8,020	768	1,949	395	782
Derivative gain (loss)	-	-	2,850	-	-
Other interest and debt expense	-	-	(3,652)	(3,020)	(4,996)
Net non operating revenues (expenses)	8,020	768	1,147	(2,625)	(4,214)
Change in net position	2,517	749	4,790	1,534	(124)
Net position - beginning of year	294,780	129	(61,253)	(62,533)	259
Net contributions /(withdrawals) by participants	-	-	-	-	-
Net position - end of period	$ 297,297	$ 878	$ (56,463)	$ (60,999)	$ 135

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
Operating revenues					
Sales of electric energy	$ 32,852	$ 81	$ 84,978	$ 22,877	$ 135,506
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	32,852	81	84,978	22,877	135,506
Operating expenses					
Operations and maintenance	20,560	84	75,807	13,064	122,355
Depreciation, depletion and amortization	11,690	-	5,156	4,935	8,353
Amortization of nuclear fuel	6,034	-	-	-	-
Decommissioning	676	-	-	-	183
Total operating expenses	38,960	84	80,963	17,999	130,891
Operating income (loss)	(6,108)	(3)	4,015	4,878	4,615
Non operating revenues (expenses)					
Investment and other income	(1,776)	94	691	191	412
Derivative gain (loss)	-	-	3,485	(616)	-
Other interest and debt expense	-	-	(3,709)	(4,417)	(5,184)
Net non operating revenues (expenses)	(1,776)	94	467	(4,842)	(4,772)
Change in net position	(7,884)	91	4,482	36	(157)
Net position - beginning of year	310,244	199	(67,485)	(64,819)	323
Net contributions /(withdrawals) by participants	-	-	-	-	-
Net position - end of period	$ 302,360	$ 290	$ (63,003)	$ (64,783)	$ 166

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
Operating revenues					
Sales of electric energy	$ 1,979	$ 12,244	$ 7,142	$ 96,287	$ 7,648
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	1,979	12,244	7,142	96,287	7,648
Operating expenses					
Operations and maintenance	697	5,347	2,294	21,083	3,332
Depreciation, depletion and amortization	749	5,807	4,322	13,686	2,987
Amortization of nuclear fuel	-	-	-	-	-
Decommissioning	11	-	-	-	12
Total operating expenses	1,457	11,154	6,616	34,769	6,331
Operating income (loss)	522	1,090	526	61,518	1,317
Non operating revenues (expenses)					
Investment and other income	105	480	187	1,436	695
Derivative gain (loss)	-	-	-	-	-
Other interest and debt expense	(438)	(229)	(105)	(3,643)	(1,533)
Net non operating revenues (expenses)	(333)	251	82	(2,207)	(838)
Change in net position	189	1,341	608	59,311	479
Net position - beginning of year	(5,292)	(9,334)	(8,092)	(56,730)	(11,177)
Net contributions /(withdrawals) by participants	-	-	-	-	-
Net position - end of period	$ (5,103)	$ (7,993)	$ (7,484)	$ 2,581	$ (10,698)

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
Operating revenues					
Sales of electric energy	$ 2,143	$ 16,927	$ 7,651	$ 33,835	$ 7,923
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	2,143	16,927	7,651	33,835	7,923
Operating expenses					
Operations and maintenance	774	9,624	2,550	21,694	3,676
Depreciation, depletion and amortization	762	5,807	4,322	13,686	2,987
Amortization of nuclear fuel	-	-	-	-	-
Decommissioning	11	-	-	-	11
Total operating expenses	1,547	15,431	6,872	35,380	6,674
Operating income (loss)	596	1,496	779	(1,545)	1,249
Non operating revenues (expenses)					
Investment and other income	58	231	75	601	526
Derivative gain (loss)	-	-	-	-	-
Other interest and debt expense	(474)	(286)	(112)	(1,177)	(1,498)
Net non operating revenues (expenses)	(416)	(55)	(37)	(576)	(972)
Change in net position	180	1,441	742	(2,121)	277
Net position - beginning of year	(5,643)	(12,315)	(9,669)	(52,665)	(11,908)
Net contributions /(withdrawals) by participants	-	-	-	-	-
Net position - end of period	$ (5,463)	$ (10,874)	$ (8,927)	$ (54,786)	$ (11,631)

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	TRANSMISSION			
	Southern Transmission System Project	Southern Transmission System Renewal Project	Mead-Phoenix Project	Mead-Adelanto Project
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ -
Sales of transmission services	27,483	-	2,009	4,224
Sales of natural gas	-	-	-	-
Total operating revenues	27,483	-	2,009	4,224
Operating expenses				
Operations and maintenance	12,113	-	833	2,174
Depreciation, depletion and amortization	2,023	-	1,396	3,166
Amortization of nuclear fuel	-	-	-	-
Decommissioning	-	-	-	-
Total operating expenses	14,136	-	2,229	5,340
Operating income (loss)	13,347	-	(220)	(1,116)
Non operating revenues (expenses)				
Investment and other income	(30)	-	107	95
Derivative gain (loss)	-	-	-	-
Other interest and debt expense	(2,601)	-	(158)	(196)
Net non operating revenues (expenses)	(2,631)	-	(51)	(101)
Change in net position	10,716	-	(271)	(1,217)
Net position - beginning of year	(7,235)	-	22,898	58,126
Net contributions /(withdrawals) by participants	-	-	-	-
Net position - end of period	$ 3,481	$ -	$ 22,627	$ 56,909

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	TRANSMISSION		
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project
Operating revenues			
Sales of electric energy	$ -	$ -	$ -
Sales of transmission services	48,135	1,802	3,184
Sales of natural gas	-	-	-
Total operating revenues	48,135	1,802	3,184
Operating expenses			
Operations and maintenance	12,427	655	1,831
Depreciation, depletion and amortization	2,023	1,396	3,165
Amortization of nuclear fuel	-	-	-
Decommissioning	-	-	-
Total operating expenses	14,450	2,051	4,996
Operating income (loss)	33,685	(249)	(1,812)
Non operating revenues (expenses)			
Investment and other income	376	54	51
Derivative gain (loss)	-	-	-
Other interest and debt expense	(3,504)	(169)	(209)
Net non operating revenues (expenses)	(3,128)	(115)	(158)
Change in net position	30,557	(364)	(1,970)
Net position - beginning of year	(69,125)	23,465	62,119
Net contributions /(withdrawals) by participants	-	-	-
Net position - end of period	$ (38,568)	$ 23,101	$ 60,149

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ 221,931
Sales of transmission services	-	-	-	-
Sales of natural gas	1,809	3,367	12,264	-
Total operating revenues	1,809	3,367	12,264	221,931
Operating expenses				
Operations and maintenance	607	1,155	6,275	224,411
Depreciation, depletion and amortization	797	1,186	-	-
Amortization of nuclear fuel	-	-	-	-
Decommissioning	19	4	-	-
Total operating expenses	1,423	2,345	6,275	224,411
Operating income (loss)	386	1,022	5,989	(2,480)
Non operating revenues (expenses)				
Investment and other income	84	1,131	520	2,619
Derivative gain (loss)	-	-	-	-
Other interest and debt expense	(274)	(647)	(6,701)	-
Net non operating revenues (expenses)	(190)	484	(6,181)	2,619
Change in net position	196	1,506	(192)	139
Net position - beginning of year	3,092	33,676	(91,769)	564
Net contributions /(withdrawals) by participants	-	-	-	-
Net position - end of period	$ 3,288	$ 35,182	$ (91,961)	$ 703

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ 236,368
Sales of transmission services	-	-	-	-
Sales of natural gas	2,619	4,591	11,640	-
Total operating revenues	2,619	4,591	11,640	236,368
Operating expenses				
Operations and maintenance	1,113	1,846	6,186	237,178
Depreciation, depletion and amortization	1,352	2,917	-	-
Amortization of nuclear fuel	-	-	-	-
Decommissioning	19	4	-	-
Total operating expenses	2,484	4,767	6,186	237,178
Operating income (loss)	135	(176)	5,454	(810)
Non operating revenues (expenses)				
Investment and other income	42	302	478	1,250
Derivative gain (loss)	-	-	-	-
Other interest and debt expense	(310)	(731)	(6,964)	-
Net non operating revenues (expenses)	(268)	(429)	(6,486)	1,250
Change in net position	(133)	(605)	(1,032)	440
Net position - beginning of year	3,012	31,552	(90,267)	(5)
Net contributions /(withdrawals) by participants	-	-	-	-
Net position - end of period	$ 2,879	$ 30,947	$ (91,299)	$ 435

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Project Stabilization Fund	SCPPA Fund	**Total Combined**
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ 525,690
Sales of transmission services	-	-	-	33,716
Sales of natural gas	-	-	-	17,440
Total operating revenues	-	-	-	576,846
Operating expenses				
Operations and maintenance	-	-	387	416,793
Depreciation, depletion and amortization	-	-	94	65,626
Amortization of nuclear fuel	-	-	-	5,732
Decommissioning	-	-	-	905
Total operating expenses	-	-	481	489,056
Operating income (loss)	-	-	(481)	87,790
Non operating revenues (expenses)				
Investment and other income	-	3,578	391	23,312
Derivative gain (loss)	-	-	-	2,850
Other interest and debt expense	-	-	-	(28,193)
Net non operating revenues (expenses)	-	3,578	391	(2,031)
Change in net position	-	3,578	(90)	85,759
Net position - beginning of year	-	122,938	3,701	226,748
Net contributions /(withdrawals) by participants	-	6,412	-	6,412
Net position - end of period	$ -	$ 132,928	$ 3,611	$ 318,919

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Project Stabilization Fund	SCPPA Fund	**Total Combined**
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ 581,141
Sales of transmission services	-	-	-	53,121
Sales of natural gas	-	-	-	18,850
Total operating revenues	-	-	-	653,112
Operating expenses				
Operations and maintenance	-	-	118	531,542
Depreciation, depletion and amortization	-	-	100	68,651
Amortization of nuclear fuel	-	-	-	6,034
Decommissioning	-	-	-	904
Total operating expenses	-	-	218	607,131
Operating income (loss)	-	-	(218)	45,981
Non operating revenues (expenses)				
Investment and other income	-	505	122	4,283
Derivative gain (loss)	-	-	-	2,869
Other interest and debt expense	-	-	-	(28,744)
Net non operating revenues (expenses)	-	505	122	(21,592)
Change in net position	-	505	(96)	24,389
Net position - beginning of year	-	113,388	3,892	164,293
Net contributions /(withdrawals) by participants	-	7,005	-	7,005
Net position - end of period	$ -	$ 120,898	$ 3,796	$ 195,687

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
Cash flows from operating activities					
Receipts from participants	$ 30,034	$ 6,060	$ 32,985	$ 11,852	$ 39,880
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(21,240)	(224)	(21,345)	(2,970)	(15,116)
Other disbursements and receipts	-	(4,953)	250	49	2
Net cash flows provided by (used for) operating activities	8,794	883	11,890	8,931	24,766
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants,net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	(12,977)	-	(22)	(83)	(2,692)
Lease interest payments	-	-	(97)	(52)	-
Debt interest and swap payments	-	-	(4,245)	(2,624)	(5,557)
Proceeds from sale of bonds	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-
Principal payments on debt	-	-	(10,760)	(13,245)	(10,830)
Principal payments on leases	-	-	(118)	(38)	-
Payment for bond issue costs	-	-	-	-	-
Net cash provided by (used for) capital and related financing activities	(12,977)	-	(15,242)	(16,042)	(19,079)
Cash flows from investing activities					
Interest received on investments	670	18	1,148	247	449
Purchases of investments	(7,061)	-	(61,171)	(9,962)	(24,877)
Proceeds from sale/maturity of investments	10,950	-	50,960	15,450	21,090
Net cash provided by (used for) investing activities	4,559	18	(9,063)	5,735	(3,338)
Net increase (decrease) in cash and cash equivalents	376	901	(12,415)	(1,376)	2,349
Cash and cash equivalents, beginning of year	14,091	209	25,007	9,333	15,295
Cash and cash equivalents, end of period	$ 14,467	$ 1,110	$ 12,592	$ 7,957	$ 17,644
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ (5,503)	$ (19)	$ 3,643	$ 4,159	$ 4,090
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:					
Depreciation, depletion and amortization	11,411	-	4,737	4,705	8,560
Decommissioning	676	-	-	-	183
Amortization of nuclear fuel	5,732	-	-	-	-
Changes in assets and liabilities:					
Accounts receivable	(1,539)	-	(147)	(148)	-
Accounts payable and accruals	(2,609)	5,862	(587)	2,218	6,737
Other	626	(4,960)	4,244	(2,003)	5,196
Net cash provided by (used for) operating activities	$ 8,794	$ 883	$ 11,890	$ 8,931	$ 24,766
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash/cash equivalents - restricted	4,752	-	8,967	3,869	7,251
Cash/cash equivalents - unrestricted	9,715	1,110	3,625	4,088	10,393
	$ 14,467	$ 1,110	$ 12,592	$ 7,957	$ 17,644

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	GENERATION				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project
Cash flows from operating activities					
Receipts from participants	$ 31,707	$ 18	$ 29,211	$ 11,078	$ 33,184
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(28,160)	(121)	(16,866)	(2,294)	(17,345)
Other disbursements and receipts	11,182	(2)	(335)	87	4
Net cash flows provided by (used for) operating activities	14,729	(105)	12,010	8,871	15,843
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants,net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	(10,118)	-	3	(135)	(2,852)
Lease interest payments	-	-	(112)	(54)	-
Debt interest and swap payments	-	-	(4,584)	(3,549)	(5,728)
Proceeds from sale of bonds	-	-	-	72,415	-
Transfer of funds from (to) escrow	-	-	-	(72,596)	-
Principal payments on debt	-	-	(13,245)	(5,855)	(10,490)
Principal payments on leases	-	-	(104)	(36)	-
Payment for bond issue costs	-	-	-	(785)	-
Net cash provided by (used for) capital and related financing activities	(10,118)	-	(18,042)	(10,595)	(19,070)
Cash flows from investing activities					
Interest received on investments	342	4	433	50	206
Purchases of investments	(12,653)	-	(39,649)	(14,821)	(63,463)
Proceeds from sale/maturity of investments	5,500	-	50,907	13,450	63,260
Net cash provided by (used for) investing activities	(6,811)	4	11,691	(1,321)	3
Net increase (decrease) in cash and cash equivalents	(2,200)	(101)	5,659	(3,045)	(3,224)
Cash and cash equivalents, beginning of year	18,042	271	19,518	5,755	22,708
Cash and cash equivalents, end of period	$ 15,842	$ 170	$ 25,177	$ 2,710	$ 19,484
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ (6,108)	$ (3)	$ 4,015	$ 4,878	$ 4,615
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:					
Depreciation, depletion and amortization	11,690	-	5,156	4,935	8,353
Decommissioning	676	-	-	-	183
Amortization of nuclear fuel	6,034	-	-	-	-
Changes in assets and liabilities:					
Accounts receivable	(73)	(7)	631	(56)	3,036
Accounts payable and accruals	2,128	(80)	(1,533)	863	(631)
Other	382	(15)	3,741	(1,749)	287
Net cash provided by (used for) operating activities	$ 14,729	$ (105)	$ 12,010	$ 8,871	$ 15,843
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash/cash equivalents - restricted	5,103	-	14,887	2,076	7,307
Cash/cash equivalents - unrestricted	10,739	170	10,290	634	12,177
	$ 15,842	$ 170	$ 25,177	$ 2,710	$ 19,484

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
Cash flows from operating activities					
Receipts from participants	$ 2,437	$ 15,106	$ 6,845	$ 41,796	$ 10,910
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(1,222)	(5,562)	(2,444)	(20,721)	(4,049)
Other disbursements and receipts	2	1	(1)	(1)	439
Net cash flows provided by (used for) operating activities	1,217	9,545	4,400	21,074	7,300
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants,net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	-	-	-	-	-
Lease interest payments	-	-	-	-	-
Debt interest and swap payments	(788)	(2,155)	(1,825)	(6,246)	(2,356)
Proceeds from sale of bonds	-	-	-	171,135	-
Transfer of funds from (to) escrow	-	-	-	(242,118)	-
Principal payments on debt	(1,225)	(10,590)	(6,620)	(12,265)	(4,735)
Principal payments on leases	-	-	-	-	-
Payment for bond issue costs	-	-	-	(662)	-
Net cash provided by (used for) capital and related financing activities	(2,013)	(12,745)	(8,445)	(90,156)	(7,091)
Cash flows from investing activities					
Interest received on investments	55	301	141	1,371	179
Purchases of investments	(2,233)	(15,002)	(4,376)	(13,943)	(3,547)
Proceeds from sale/maturity of investments	2,720	9,960	6,420	75,188	11,920
Net cash provided by (used for) investing activities	542	(4,741)	2,185	62,616	8,552
Net increase (decrease) in cash and cash equivalents	(254)	(7,941)	(1,860)	(6,466)	8,761
Cash and cash equivalents, beginning of year	2,522	13,935	6,308	16,665	4,007
Cash and cash equivalents, end of period	$ 2,268	$ 5,994	$ 4,448	$ 10,199	$ 12,768
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ 522	$ 1,090	$ 526	$ 61,518	$ 1,317
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:					
Depreciation, depletion and amortization	749	-	-	-	2,987
Decommissioning	11	-	-	-	12
Amortization of nuclear fuel	-	-	-	-	-
Changes in assets and liabilities:					
Accounts receivable	-	-	-	-	2,762
Accounts payable and accruals	187	2,648	(448)	(54,742)	225
Other	(252)	5,807	4,322	14,298	(3)
Net cash provided by (used for) operating activities	$ 1,217	$ 9,545	$ 4,400	$ 21,074	$ 7,300
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash/cash equivalents - restricted	1,228	2,638	28	2,487	9,110
Cash/cash equivalents - unrestricted	1,040	3,356	4,420	7,712	3,658
	$ 2,268	$ 5,994	$ 4,448	$ 10,199	$ 12,768

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	GREEN POWER				
	Tieton Hydropower Project	Milford I Wind Project	Milford II Wind Project	Windy Point/ Windy Flats Project	Linden Wind Project
Cash flows from operating activities					
Receipts from participants	$ 2,352	$ 18,242	$ 9,219	$ 44,096	$ 8,094
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(1,592)	(9,812)	(3,630)	(21,382)	(3,923)
Other disbursements and receipts	-	6	-	16	42
Net cash flows provided by (used for) operating activities	760	8,436	5,589	22,730	4,213
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants,net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	-	-	-	-	-
Lease interest payments	-	-	-	-	(8)
Debt interest and swap payments	(820)	(2,399)	(1,983)	(6,538)	(2,469)
Proceeds from sale of bonds	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-
Principal payments on debt	(1,165)	(10,105)	(6,300)	(11,680)	(4,510)
Principal payments on leases	-	-	-	-	(10)
Payment for bond issue costs	-	-	-	-	-
Net cash provided by (used for) capital and related financing activities	(1,985)	(12,504)	(8,283)	(18,218)	(6,997)
Cash flows from investing activities					
Interest received on investments	32	112	34	311	79
Purchases of investments	(1,915)	(11,299)	(11,092)	(31,546)	(8,583)
Proceeds from sale/maturity of investments	2,210	14,750	11,412	28,000	8,240
Net cash provided by (used for) investing activities	327	3,563	354	(3,235)	(264)
Net increase (decrease) in cash and cash equivalents	(898)	(505)	(2,340)	1,277	(3,048)
Cash and cash equivalents, beginning of year	3,322	8,847	5,317	11,142	6,240
Cash and cash equivalents, end of period	$ 2,424	$ 8,342	$ 2,977	$ 12,419	$ 3,192
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ 596	$ 1,496	$ 779	$ (1,545)	$ 1,249
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:					
Depreciation, depletion and amortization	762	-	-	-	2,987
Decommissioning	11	-	-	-	11
Amortization of nuclear fuel	-	-	-	-	-
Changes in assets and liabilities:					
Accounts receivable	-	-	327	590	(649)
Accounts payable and accruals	(449)	1,133	161	9,373	210
Other	(160)	5,807	4,322	14,312	405
Net cash provided by (used for) operating activities	$ 760	$ 8,436	$ 5,589	$ 22,730	$ 4,213
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash/cash equivalents - restricted	1,548	3,366	157	3,542	1,413
Cash/cash equivalents - unrestricted	876	4,976	2,820	8,877	1,779
	$ 2,424	$ 8,342	$ 2,977	$ 12,419	$ 3,192

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	TRANSMISSION			
	Southern Transmission System Project	Southern Transmission System Renewal Project	Mead-Phoenix Project	Mead-Adelanto Project
Cash flows from operating activities				
Receipts from participants	$ 32,550	$ -	$ 2,229	$ 3,713
Receipts from sale of oil and gas	-	-	-	-
Payments to operating managers	(21,814)	-	(974)	(1,522)
Other disbursements and receipts	5	-	1	1
Net cash flows provided by (used for) operating activities	10,741	-	1,256	2,192
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants,net	-	-	-	-
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	-	(119,676)	(196)	-
Lease interest payments	-	-	-	-
Debt interest and swap payments	(4,420)	(5,274)	(355)	(446)
Proceeds from sale of bonds	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-
Principal payments on debt	(62,825)	-	(1,535)	(1,870)
Principal payments on leases	-	-	-	-
Payment for bond issue costs	-	(114)	-	-
Net cash provided by (used for) capital and related financing activities	(67,245)	(125,064)	(2,086)	(2,316)
Cash flows from investing activities				
Interest received on investments	272	3,876	95	75
Purchases of investments	(13,612)	(180,853)	(1,023)	(1,679)
Proceeds from sale/maturity of investments	50,760	225,000	1,460	1,580
Net cash provided by (used for) investing activities	37,420	48,023	532	(24)
Net increase (decrease) in cash and cash equivalents	(19,084)	(77,041)	(298)	(148)
Cash and cash equivalents, beginning of year	24,247	130,669	3,706	2,906
Cash and cash equivalents, end of period	$ 5,163	$ 53,628	$ 3,408	$ 2,758
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ 13,347	$ -	$ (220)	$ (1,116)
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	2,023	-	1,396	3,166
Decommissioning	-	-	-	-
Amortization of nuclear fuel	-	-	-	-
Changes in assets and liabilities:				
Accounts receivable	(3,323)	-	-	(96)
Accounts payable and accruals	(724)	-	69	(291)
Other	(582)	-	11	529
Net cash provided by (used for) operating activities	$ 10,741	$ -	$ 1,256	$ 2,192
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash/cash equivalents - restricted	4,510	53,628	1,848	1,483
Cash/cash equivalents - unrestricted	653	-	1,560	1,275
	$ 5,163	$ 53,628	$ 3,408	$ 2,758

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	TRANSMISSION		
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project
Cash flows from operating activities			
Receipts from participants	$ 52,183	$ 2,478	$ 4,304
Receipts from sale of oil and gas	-	-	-
Payments to operating managers	(10,678)	(1,169)	(5,742)
Other disbursements and receipts	(4)	6	(277)
Net cash flows provided by (used for) operating activities	41,501	1,315	(1,715)
Cash flows from noncapital financing activities			
Advances (withdrawals) by participants,net	-	-	-
Cash flows from capital financing activities			
Additions to plant and prepaid projects, net	-	(41)	-
Lease interest payments	-	-	-
Debt interest and swap payments	(5,856)	(385)	(491)
Proceeds from sale of bonds	-	-	-
Transfer of funds from (to) escrow	-	-	-
Principal payments on debt	(59,415)	(1,475)	(1,780)
Principal payments on leases	-	-	-
Payment for bond issue costs	-	-	-
Net cash provided by (used for) capital and related financing activities	(65,271)	(1,901)	(2,271)
Cash flows from investing activities			
Interest received on investments	92	42	46
Purchases of investments	(38,344)	(2,710)	(6,936)
Proceeds from sale/maturity of investments	49,400	2,599	12,702
Net cash provided by (used for) investing activities	11,148	(69)	5,812
Net increase (decrease) in cash and cash equivalents	(12,622)	(655)	1,826
Cash and cash equivalents, beginning of year	19,792	3,758	1,844
Cash and cash equivalents, end of period	$ 7,170	$ 3,103	$ 3,670
Reconciliation of operating income (loss) to net cash provided by operating activities			
Operating income (loss)	$ 33,685	$ (249)	$ (1,812)
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	2,023	1,396	3,165
Decommissioning	-	-	-
Amortization of nuclear fuel	-	-	-
Changes in assets and liabilities:			
Accounts receivable	3,958	-	-
Accounts payable and accruals	1,835	267	(2,434)
Other	-	(99)	(634)
Net cash provided by (used for) operating activities	$ 41,501	$ 1,315	$ (1,715)
Cash and cash equivalents as stated in the Combined Statements of Net Position			
Cash/cash equivalents - restricted	6,734	1,226	1,443
Cash/cash equivalents - unrestricted	436	1,877	2,227
	$ 7,170	$ 3,103	$ 3,670

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
Cash flows from operating activities				
Receipts from participants	$ 1,247	$ 2,410	$ 11,397	$ 209,460
Receipts from sale of oil and gas	249	438	3,103	-
Payments to operating managers	(510)	(1,059)	(347)	(206,582)
Other disbursements and receipts	7	16	2	7,766
Net cash flows provided by (used for) operating activities	993	1,805	14,155	10,644
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants,net	600	12	-	-
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	(1)	(4)	-	-
Lease interest payments	-	-	-	-
Debt interest and swap payments	(310)	(731)	(6,560)	-
Proceeds from sale of bonds	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-
Principal payments on debt	(1,270)	(2,985)	(11,250)	-
Principal payments on leases	-	-	-	-
Payment for bond issue costs	-	-	-	-
Net cash provided by (used for) capital and related financing activities	(1,581)	(3,720)	(17,810)	-
Cash flows from investing activities				
Interest received on investments	82	709	562	2,026
Purchases of investments	-	(21,891)	(11,607)	(37,623)
Proceeds from sale/maturity of investments	1,080	24,830	16,453	28,300
Net cash provided by (used for) investing activities	1,162	3,648	5,408	(7,297)
Net increase (decrease) in cash and cash equivalents	1,174	1,745	1,753	3,347
Cash and cash equivalents, beginning of year	4,800	5,480	4,068	84,690
Cash and cash equivalents, end of period	$ 5,974	$ 7,225	$ 5,821	$ 88,037
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ 386	$ 1,022	$ 5,989	$ (2,480)
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	797	1,186	-	-
Decommissioning	19	4	-	-
Amortization of nuclear fuel	-	-	-	-
Changes in assets and liabilities:				
Accounts receivable	(52)	148	75	6,246
Accounts payable and accruals	228	(309)	2,075	6,895
Other	(385)	(246)	6,016	(17)
Net cash provided by (used for) operating activities	$ 993	$ 1,805	$ 14,155	$ 10,644
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash/cash equivalents - restricted	2,717	5,114	4,846	27
Cash/cash equivalents - unrestricted	3,257	2,111	975	88,010
	$ 5,974	$ 7,225	$ 5,821	$ 88,037

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	NATURAL GAS			PPAs
	Pinedale Project	Barnett Project	Prepaid Natural Gas Project	Power Purchase Agreements Combined Projects
Cash flows from operating activities				
Receipts from participants	$ 1,480	$ 2,451	$ 16,252	$ 180,633
Receipts from sale of oil and gas	546	1,970	-	-
Payments to operating managers	(1,356)	(2,497)	(479)	(191,082)
Other disbursements and receipts	15	(11)	(2,848)	19,470
Net cash flows provided by (used for) operating activities	685	1,913	12,925	9,021
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants,net	(776)	6	-	-
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	(7)	(21)	-	-
Lease interest payments	-	-	-	-
Debt interest and swap payments	(348)	(819)	(6,815)	-
Proceeds from sale of bonds	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-
Principal payments on debt	(1,345)	(3,160)	(9,705)	-
Principal payments on leases	-	-	-	-
Payment for bond issue costs	-	-	-	-
Net cash provided by (used for) capital and related financing activities	(1,700)	(4,000)	(16,520)	-
Cash flows from investing activities				
Interest received on investments	29	288	444	681
Purchases of investments	-	(18,103)	(30,268)	(47,976)
Proceeds from sale/maturity of investments	1,000	17,169	33,345	44,500
Net cash provided by (used for) investing activities	1,029	(646)	3,521	(2,795)
Net increase (decrease) in cash and cash equivalents	(762)	(2,727)	(74)	6,226
Cash and cash equivalents, beginning of year	5,278	7,880	5,237	69,726
Cash and cash equivalents, end of period	$ 4,516	$ 5,153	$ 5,163	$ 75,952
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ 135	$ (176)	$ 5,454	$ (810)
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	1,352	2,917	-	-
Decommissioning	19	4	-	-
Amortization of nuclear fuel	-	-	-	-
Changes in assets and liabilities:				
Accounts receivable	(380)	(3)	(534)	(8,011)
Accounts payable and accruals	178	(296)	2,063	17,833
Other	(619)	(533)	5,942	9
Net cash provided by (used for) operating activities	$ 685	$ 1,913	$ 12,925	$ 9,021
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash/cash equivalents - restricted	2,679	3,496	4,632	32
Cash/cash equivalents - unrestricted	1,837	1,657	531	75,920
	$ 4,516	$ 5,153	$ 5,163	$ 75,952

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Projects Stabilization Fund	SCPPA Fund	**Total Combined**
Cash flows from operating activities				
Receipts from participants	$ -	$ -	$ -	$ 460,911
Receipts from sale of oil and gas	-	-	-	3,790
Payments to operating managers	-	-	-	(327,701)
Other disbursements and receipts	-	-	(387)	3,199
Net cash flows provided by (used for) operating activities	-	-	(387)	140,199
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants,net	-	6,412	387	7,411
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	-	-	-	(135,651)
Lease interest payments	-	-	-	(149)
Debt interest and swap payments	-	-	-	(43,892)
Proceeds from sale of bonds	-	-	-	171,135
Transfer of funds from (to) escrow	-	-	-	(242,118)
Principal payments on debt	-	-	-	(152,005)
Principal payments on leases	-	-	-	(156)
Payment for bond issue costs	-	-	-	(776)
Net cash provided by (used for) capital and related financing activities	-	-	-	(403,612)
Cash flows from investing activities				
Interest received on investments	-	2,075	-	14,351
Purchases of investments	-	(23,881)	-	(434,341)
Proceeds from sale/maturity of investments	-	26,155	-	580,276
Net cash provided by (used for) investing activities	-	4,349	-	160,286
Net increase (decrease) in cash and cash equivalents	-	10,761	-	(95,716)
Cash and cash equivalents, beginning of year	-	19,037	-	386,975
Cash and cash equivalents, end of period	$ -	$ 29,798	$ -	$ 291,259
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ -	$ -	$ (481)	$ 87,790
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	-	-	94	41,811
Decommissioning	-	-	-	905
Amortization of nuclear fuel	-	-	-	5,732
Changes in assets and liabilities:				
Accounts receivable	-	-	-	3,926
Accounts payable and accruals	-	-	-	(32,566)
Other	-	-	-	32,601
Net cash provided by (used for) operating activities	$ -	$ -	$ (387)	$ 140,199
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash/cash equivalents - restricted	-	29,798	-	144,301
Cash/cash equivalents - unrestricted	-	-	-	146,958
	$ -	$ 29,798	$ -	$ 291,259

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2023

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	MISCELLANEOUS			
	Project Development Fund	Projects Stabilization Fund	SCPPA Fund	**Total Combined**
Cash flows from operating activities				
Receipts from participants	$ -	$ -	$ -	$ 446,982
Receipts from sale of oil and gas	-	-	-	2,516
Payments to operating managers	-	-	-	(318,128)
Other disbursements and receipts	-	-	(118)	27,233
Net cash flows provided by (used for) operating activities	-	-	(118)	158,603
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants,net	(2,606)	7,005	118	3,747
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	-	-	-	(13,171)
Lease interest payments	-	-	-	(174)
Debt interest and swap payments	-	-	-	(42,784)
Proceeds from sale of bonds	-	-	-	72,415
Transfer of funds from (to) escrow	-	-	-	(72,596)
Principal payments on debt	-	-	-	(140,230)
Principal payments on leases	-	-	-	(150)
Payment for bond issue costs	-	-	-	(785)
Net cash provided by (used for) capital and related financing activities	-	-	-	(197,475)
Cash flows from investing activities				
Interest received on investments	-	553	-	3,778
Purchases of investments	-	(31,257)	-	(370,615)
Proceeds from sale/maturity of investments	-	26,200	-	384,644
Net cash provided by (used for) investing activities	-	(4,504)	-	17,807
Net increase (decrease) in cash and cash equivalents	(2,606)	2,501	-	(17,318)
Cash and cash equivalents, beginning of year	2,606	17,206	-	234,489
Cash and cash equivalents, end of period	$ -	$ 19,707	$ -	$ 217,171
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ -	$ -	$ (218)	$ 45,981
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:				
Depreciation, depletion and amortization	-	-	100	44,836
Decommissioning	-	-	-	904
Amortization of nuclear fuel	-	-	-	6,034
Changes in assets and liabilities:				
Accounts receivable	-	-	-	(1,171)
Accounts payable and accruals	-	-	-	30,621
Other	-	-	-	31,398
Net cash provided by (used for) operating activities	$ -	$ -	$ (118)	$ 158,603
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash/cash equivalents - restricted	-	19,707	-	79,348
Cash/cash equivalents - unrestricted	-	-	-	137,823
	$ -	$ 19,707	$ -	$ 217,171

These unaudited financial statements should be read in conjunction to the notes to the audited financial statements for the fiscal year ended June 30, 2022

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
ASSETS										
Noncurrent assets										
Investments - unrestricted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,398	$ -	$ -
Total noncurrent assets	-	-	-	-	-	-	-	12,398	-	-
Current assets										
Cash and cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash and cash equivalents - unrestricted	-	899	5,199	1,208	4,567	5,328	1,048	6,876	550	2,597
Interest receivable	-	1	10	1	7	7	1	10	1	7
Accounts receivable	-	94	-	32	-	-	35	2,698	39	-
Prepaid and other assets	-	-	5	2	2	11	3	10	5	1
Total current assets	-	994	5,214	1,243	4,576	5,346	1,087	9,594	595	2,605
Total assets	$ -	$ 994	$ 5,214	$ 1,243	$ 4,576	$ 5,346	$ 1,087	$ 21,992	$ 595	$ 2,605
LIABILITIES										
Current Liabilities										
Advances from participants due within one year	$ -	$ 500	$ 1,650	$ 400	$ 960	$ -	$ 400	$ 400	$ 171	$ 960
Accounts payable and accruals	-	493	3,539	842	3,591	5,333	686	21,431	423	1,632
Total liabilities	-	993	5,189	1,242	4,551	5,333	1,086	21,831	594	2,592
Total liabilities	-	993	5,189	1,242	4,551	5,333	1,086	21,831	594	2,592
NET POSITION										
Unrestricted	-	1	25	1	25	13	1	161	1	13
Total net position	-	1	25	1	25	13	1	161	1	13
Total liabilities and net position	$ -	$ 994	$ 5,214	$ 1,243	$ 4,576	$ 5,346	$ 1,087	$ 21,992	$ 595	$ 2,605

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
ASSETS										
Noncurrent assets										
Investments - unrestricted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total noncurrent assets	-	-	-	-	-	-	-	-	-	-
Current assets										
Cash and cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash and cash equivalents - unrestricted	3,783	4,028	1,737	2,136	1,191	2,442	223	2,841	11,456	2,562
Interest receivable	6	5	2	2	2	2	-	3	7	4
Accounts receivable	-	-	42	95	40	81	-	31	-	-
Prepaid and other assets	3	4	5	12	4	8	2	15	15	6
Total current assets	3,792	4,037	1,786	2,245	1,237	2,533	225	2,890	11,478	2,572
Total assets	$ 3,792	$ 4,037	$ 1,786	$ 2,245	$ 1,237	$ 2,533	$ 225	$ 2,890	$ 11,478	$ 2,572
LIABILITIES										
Current Liabilities										
Advances from participants due within one year	$ 2,000	$ 2,000	$ 600	$ 800	$ 300	$ 900	$ 90	$ 420	$ 400	$ -
Accounts payable and accruals	1,777	2,019	1,184	1,443	936	1,631	135	2,467	11,036	2,565
Total liabilities	3,777	4,019	1,784	2,243	1,236	2,531	225	2,887	11,436	2,565
Total liabilities	3,777	4,019	1,784	2,243	1,236	2,531	225	2,887	11,436	2,565
NET POSITION										
Unrestricted	15	18	2	2	1	2	-	3	42	7
Total net position	15	18	2	2	1	2	-	3	42	7
Total liabilities and net position	$ 3,792	$ 4,037	$ 1,786	$ 2,245	$ 1,237	$ 2,533	$ 225	$ 2,890	$ 11,478	$ 2,572

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS										
	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	Daggett Solar 2 Project	**Totals**
ASSETS											
Noncurrent assets											
Investments - unrestricted	$ 1,988	$ -	$ -	$ -	$ -	$ 23,640	$ -	$ -	$ -	$ -	$ 38,026
Total noncurrent assets	1,988	-	-	-	-	23,640	-	-	-	-	38,026
Current assets											
Cash and cash equivalents - restricted	2	-	-	-	25	-	-	-	-	-	27
Cash and cash equivalents - unrestricted	7,701	3,128	1,484	1,348	588	916	2,230	4,633	2,471	2,840	88,010
Interest receivable	22	5	1	1	3	42	2	4	2	2	162
Accounts receivable	7	-	602	-	-	-	-	1,936	-	286	6,018
Prepaid and other assets	-	2	1	2	2	8	11	5	7	-	151
Total current assets	7,732	3,135	2,088	1,351	618	966	2,243	6,578	2,480	3,128	94,368
Total assets	$ 9,720	$ 3,135	$ 2,088	$ 1,351	$ 618	$ 24,606	$ 2,243	$ 6,578	$ 2,480	$ 3,128	$ 132,394
LIABILITIES											
Current Liabilities											
Advances from participants due within one year	$ 400	$ 2,000	$ 400	$ 400	$ 12	$ 4,600	$ 174	$ 500	$ 504	$ 170	$ 22,111
Accounts payable and accruals	9,249	1,121	1,682	950	603	19,742	2,068	6,072	1,974	2,956	109,580
Total liabilities	9,649	3,121	2,082	1,350	615	24,342	2,242	6,572	2,478	3,126	131,691
Total liabilities	9,649	3,121	2,082	1,350	615	24,342	2,242	6,572	2,478	3,126	131,691
NET POSITION											
Unrestricted	71	14	6	1	3	264	1	6	2	2	703
Total net position	71	14	6	1	3	264	1	6	2	2	703
Total liabilities and net position	$ 9,720	$ 3,135	$ 2,088	$ 1,351	$ 618	$ 24,606	$ 2,243	$ 6,578	$ 2,480	$ 3,128	$ 132,394

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
ASSETS										
Noncurrent assets										
Investments - unrestricted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,994	$ -	$ -
Current assets										
Cash and cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash and cash equivalents - unrestricted	1,941	1,175	5,248	988	5,046	5,281	1,085	7,083	764	2,834
Interest receivable	-	-	2	-	2	3	-	26	-	-
Accounts receivable	1	135	-	-	-	-	271	-	413	4
Prepaid and other assets	-	-	7	2	3	12	3	14	5	2
Total current assets	1,942	1,310	5,257	990	5,051	5,296	1,359	7,123	1,182	2,840
Total assets	$ 1,942	$ 1,310	$ 5,257	$ 990	$ 5,051	$ 5,296	$ 1,359	$ 18,117	$ 1,182	$ 2,840
LIABILITIES										
Current Liabilities										
Advances from participants due within one year	$ 857	$ 500	$ 1,650	$ 400	$ 960	$ -	$ 400	$ 400	$ 171	$ 960
Accounts payable and accruals	1,085	810	3,591	590	4,075	5,283	959	17,610	1,011	1,873
Total liabilities	1,942	1,310	5,241	990	5,035	5,283	1,359	18,010	1,182	2,833
NET POSITION										
Unrestricted	-	-	16	-	16	13	-	107	-	7
Total net position	-	-	16	-	16	13	-	107	-	7
Total liabilities and net position	$ 1,942	$ 1,310	$ 5,257	$ 990	$ 5,051	$ 5,296	$ 1,359	$ 18,117	$ 1,182	$ 2,840

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
ASSETS										
Noncurrent assets										
Investments - unrestricted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,487	$ -
Current assets										
Cash and cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash and cash equivalents - unrestricted	3,242	3,722	1,198	2,994	939	3,133	196	2,765	5,628	2,472
Interest receivable	2	2	-	-	-	-	-	-	13	2
Accounts receivable	-	-	316	951	326	809	-	3,346	1,765	-
Prepaid and other assets	3	4	5	13	5	7	3	20	15	8
Total current assets	3,247	3,728	1,519	3,958	1,270	3,949	199	6,131	7,421	2,482
Total assets	$ 3,247	$ 3,728	$ 1,519	$ 3,958	$ 1,270	$ 3,949	$ 199	$ 6,131	$ 10,908	$ 2,482
LIABILITIES										
Current Liabilities										
Advances from participants due within one year	$ 2,000	$ 2,000	$ 600	$ 800	$ 300	$ 900	$ 90	$ 420	$ 400	$ -
Accounts payable and accruals	1,236	1,715	919	3,158	970	3,049	109	5,711	10,422	2,477
Total liabilities	3,236	3,715	1,519	3,958	1,270	3,949	199	6,131	10,822	2,477
NET POSITION										
Unrestricted	11	13	-	-	-	-	-	-	86	5
Total net position	11	13	-	-	-	-	-	-	86	5
Total liabilities and net position	$ 3,247	$ 3,728	$ 1,519	$ 3,958	$ 1,270	$ 3,949	$ 199	$ 6,131	$ 10,908	$ 2,482

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Net Position
As of December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	Totals
ASSETS										
Noncurrent assets										
Investments - unrestricted	$ 7,774	$ -	$ -	$ -	$ -	$ 12,994	$ -	$ -	$ -	$ 35,249
Current assets										
Cash and cash equivalents - restricted	1	-	-	-	31	-	-	-	-	32
Cash and cash equivalents - unrestricted	1,622	2,813	1,233	805	831	5,746	2,025	1,828	1,283	75,920
Interest receivable	43	2	-	-	3	34	4	-	-	138
Accounts receivable	11	-	-	1,240	1	-	-	1,676	3,267	14,532
Prepaid and other assets	-	2	1	2	2	10	11	5	-	164
Total current assets	1,677	2,817	1,234	2,047	868	5,790	2,040	3,509	4,550	90,786
Total assets	$ 9,451	$ 2,817	$ 1,234	$ 2,047	$ 868	$ 18,784	$ 2,040	$ 3,509	$ 4,550	$ 126,035
LIABILITIES										
Current Liabilities										
Advances from participants due within one year	$ 400	$ 2,000	$ 400	$ 400	$ 12	$ 2,298	$ 174	$ 500	$ 252	$ 20,244
Accounts payable and accruals	8,998	809	834	1,647	853	16,389	1,866	3,009	4,298	105,356
Total liabilities	9,398	2,809	1,234	2,047	865	18,687	2,040	3,509	4,550	125,600
NET POSITION										
Unrestricted	53	8	-	-	3	97	-	-	-	435
Total net position	53	8	-	-	3	97	-	-	-	435
Total liabilities and net position	$ 9,451	$ 2,817	$ 1,234	$ 2,047	$ 868	$ 18,784	$ 2,040	$ 3,509	$ 4,550	$ 126,035

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
Operating revenues										
Sales of electric energy	$ -	$ 406	$ 8,699	$ 1,136	$ 5,689	$ 28,038	$ 1,975	$ 14,554	$ 2,888	$ 3,885
Total operating revenues	-	406	8,699	1,136	5,689	28,038	1,975	14,554	2,888	3,885
Operating expenses										
Operations and maintenance	-	412	8,853	1,142	5,818	28,244	1,987	15,020	2,892	3,965
Total operating expenses	-	412	8,853	1,142	5,818	28,244	1,987	15,020	2,892	3,965
Operating income (loss)	-	(6)	(154)	(6)	(129)	(206)	(12)	(466)	(4)	(80)
Non operating revenues (expenses)										
Investment and other income	-	6	143	6	136	179	12	501	4	82
Net non operating revenues (expenses)	-	6	143	6	136	179	12	501	4	82
Change in net position	-	-	(11)	-	7	(27)	-	35	-	2
Net position - beginning of year	-	1	36	1	18	40	1	126	1	11
Net position - end of period	$ -	$ 1	$ 25	$ 1	$ 25	$ 13	$ 1	$ 161	$ 1	$ 13

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
Operating revenues										
Sales of electric energy	$ 9,585	$ 11,227	$ 2,270	$ 6,114	$ 2,497	$ 4,797	$ 341	$ 10,269	$ 53,434	$ 9,699
Total operating revenues	9,585	11,227	2,270	6,114	2,497	4,797	341	10,269	53,434	9,699
Operating expenses										
Operations and maintenance	9,686	11,343	2,282	6,128	2,506	4,815	342	10,292	53,538	9,760
Total operating expenses	9,686	11,343	2,282	6,128	2,506	4,815	342	10,292	53,538	9,760
Operating income (loss)	(101)	(116)	(12)	(14)	(9)	(18)	(1)	(23)	(104)	(61)
Non operating revenues (expenses)										
Investment and other income	95	109	12	14	9	17	1	21	142	61
Net non operating revenues (expenses)	95	109	12	14	9	17	1	21	142	61
Change in net position	(6)	(7)	-	-	-	(1)	-	(2)	38	-
Net position - beginning of year	21	25	2	2	1	3	-	5	4	7
Net position - end of period	$ 15	$ 18	$ 2	$ 2	$ 1	$ 2	$ -	$ 3	$ 42	$ 7

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

POWER PURCHASE AGREEMENTS

	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	Daggett Solar 2 Project	Totals
Operating revenues											
Sales of electric energy	$ (181)	$ 5,637	$ 558	$ 3,252	$ 662	$ 20,567	$ 5,287	$ 1,677	$ 6,048	$ 921	$ 221,931
Total operating revenues	(181)	5,637	558	3,252	662	20,567	5,287	1,677	6,048	921	221,931
Operating expenses											
Operations and maintenance	42	5,716	562	3,259	682	21,150	5,297	1,698	6,057	923	224,411
Total operating expenses	42	5,716	562	3,259	682	21,150	5,297	1,698	6,057	923	224,411
Operating income (loss)	(223)	(79)	(4)	(7)	(20)	(583)	(10)	(21)	(9)	(2)	(2,480)
Non operating revenues (expenses)											
Investment and other income	220	79	8	7	20	688	10	24	9	4	2,619
Net non operating revenues (expenses)	220	79	8	7	20	688	10	24	9	4	2,619
Change in net position	(3)	-	4	-	-	105	-	3	-	2	139
Net position - beginning of year	74	14	2	1	3	159	1	3	2	-	564
Net position - end of period	$ 71	$ 14	$ 6	$ 1	$ 3	$ 264	$ 1	$ 6	$ 2	$ 2	$ 703

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
Operating revenues										
Sales of electric energy	$ -	$ 207	$ 9,199	$ 1,288	$ 5,961	$ 27,366	$ 2,527	$ 5,521	$ 4,328	$ 4,232
Total operating revenues	-	207	9,199	1,288	5,961	27,366	2,527	5,521	4,328	4,232
Operating expenses										
Operations and maintenance	-	207	9,254	1,288	6,014	27,410	2,527	5,635	4,328	4,266
Total operating expenses	-	207	9,254	1,288	6,014	27,410	2,527	5,635	4,328	4,266
Operating income (loss)	-	-	(55)	-	(53)	(44)	-	(114)	-	(34)
Non operating revenues (expenses)										
Investment and other income	-	-	67	-	67	52	-	219	-	40
Net non operating revenues (expenses)	-	-	67	-	67	52	-	219	-	40
Change in net position	-	-	12	-	14	8	-	105	-	6
Net position - beginning of year	-	-	4	-	2	5	-	2	-	1
Net position - end of period	$ -	$ -	$ 16	$ -	$ 16	$ 13	$ -	$ 107	$ -	$ 7

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

POWER PURCHASE AGREEMENTS

	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
Operating revenues										
Sales of electric energy	$ 9,850	$ 11,597	$ 3,636	$ 9,613	$ 3,623	$ 7,871	$ 383	$ 16,876	$ 47,821	$ 10,347
Total operating revenues	9,850	11,597	3,636	9,613	3,623	7,871	383	16,876	47,821	10,347
Operating expenses										
Operations and maintenance	9,883	11,629	3,636	9,613	3,623	7,871	383	16,876	48,000	10,374
Total operating expenses	9,883	11,629	3,636	9,613	3,623	7,871	383	16,876	48,000	10,374
Operating income (loss)	(33)	(32)	-	-	-	-	-	-	(179)	(27)
Non operating revenues (expenses)										
Investment and other income	40	41	-	-	-	-	-	-	295	31
Net non operating revenues (expenses)	40	41	-	-	-	-	-	-	295	31
Change in net position	7	9	-	-	-	-	-	-	116	4
Net position - beginning of year	4	4	-	-	-	-	-	-	(30)	1
Net position - end of period	$ 11	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 86	$ 5

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Revenues, Expenses, and Changes in Net Position
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	Totals
Operating revenues										
Sales of electric energy	$ (10)	$ 6,120	$ 681	$ 10,147	$ 297	$ 17,903	$ 5,555	$ 1,554	$ 11,875	236,368
Total operating revenues	(10)	6,120	681	10,147	297	297	5,555	1,554	11,875	236,368
Operating expenses										
Operations and maintenance	43	6,166	681	10,147	305	18,024	5,566	1,554	11,875	237,178
Total operating expenses	43	6,166	681	10,147	305	-	-	-	-	237,178
Operating income (loss)	(53)	(46)	-	-	(8)	(121)	(11)	-	-	(810)
Non operating revenues (expenses)										
Investment and other income	111	51	-	-	11	214	11	-	-	1,250
Net non operating revenues (expenses)	111	51	-	-	11	214	11	-	-	1,250
Change in net position	58	5	-	-	3	93	-	-	-	440
Net position - beginning of year	(5)	3	-	-	-	4	-	-	-	(5)
Net position - end of period	$ 53	$ 8	$ -	$ -	$ 3	$ 97	$ -	$ -	$ -	$ 435

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
Cash flows from operating activities										
Receipts from participants	$ -	$ 68	$ 8,999	$ 951	$ 5,252	$ 27,392	$ 864	$ 10,321	$ 1,161	$ 3,635
Payments to operating managers	-	(273)	(10,258)	(759)	(5,378)	(30,594)	(1,804)	(10,636)	(2,323)	(3,613)
Other disbursements and receipts	-	(1)	1	(1)	-	(1)	668	(4)	953	9
Net cash flows provided by (used for) operating activities	-	(206)	(1,258)	191	(126)	(3,203)	(272)	(319)	(209)	31
Cash flows from investing activities										
Interest received on investments	-	6	138	6	134	190	12	376	3	79
Purchases of investments	-	-	-	-	-	-	-	(12,261)	-	-
Proceeds from sale/maturity of investments	-	-	-	-	-	-	-	-	-	-
Net cash provided by (used for) investing activities	-	6	138	6	134	190	12	(11,885)	3	79
Net increase (decrease) in cash and cash equivalents	-	(200)	(1,120)	197	8	(3,013)	(260)	(12,204)	(206)	110
Cash and cash equivalents, beginning of year	-	1,099	6,319	1,011	4,559	8,341	1,308	19,080	756	2,487
Cash and cash equivalents, end of period	$ -	$ 899	$ 5,199	$ 1,208	$ 4,567	$ 5,328	$ 1,048	$ 6,876	$ 550	$ 2,597
Reconciliation of operating income (loss) to net cash provided by operating activities										
Operating income (loss)	$ -	$ (6)	$ (154)	$ (6)	$ (129)	$ (206)	$ (12)	$ (466)	$ (4)	$ (80)
Changes in assets and liabilities:										
Accounts receivable	-	(94)	-	(32)	-	-	(1)	(2,698)	18	-
Accounts payable and accruals	-	(106)	(1,105)	229	3	(2,996)	(259)	2,846	(224)	111
Other	-	-	1	-	-	(1)	-	(1)	1	-
Net cash provided by (used for) operating activities	$ -	$ (206)	$ (1,258)	$ 191	$ (126)	$ (3,203)	$ (272)	$ (319)	$ (209)	$ 31
Cash and cash equivalents as stated in the Combined Statements of Net Position										
Cash/cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash/cash equivalents - unrestricted	-	899	5,199	1,208	4,567	5,328	1,048	6,876	550	2,597
	$ -	$ 899	$ 5,199	$ 1,208	$ 4,567	$ 5,328	$ 1,048	$ 6,876	$ 550	$ 2,597

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
Cash flows from operating activities										
Receipts from participants	$ 10,345	$ 11,765	$ 1,204	$ 2,149	$ 1,101	$ 1,697	$ 402	$ 1,429	$ 63,527	$ 10,180
Payments to operating managers	(11,047)	(12,974)	(2,018)	(4,403)	(2,076)	(3,932)	(403)	(3,126)	(52,588)	(9,565)
Other disbursements and receipts	-	-	768	2,242	847	2,007	(1)	(7)	4	-
Net cash flows provided by (used for) operating activities	(702)	(1,209)	(46)	(12)	(128)	(228)	(2)	(1,704)	10,943	615
Cash flows from investing activities										
Interest received on investments	95	110	12	14	10	18	1	23	139	63
Purchases of investments	-	-	-	-	-	-	-	-	-	-
Proceeds from sale/maturity of investments	-	-	-	-	-	-	-	-	-	-
Net cash provided by (used for) investing activities	95	110	12	14	10	18	1	23	139	63
Net increase (decrease) in cash and cash equivalents	(607)	(1,099)	(34)	2	(118)	(210)	(1)	(1,681)	11,082	678
Cash and cash equivalents, beginning of year	4,390	5,127	1,771	2,134	1,309	2,652	224	4,522	374	1,884
Cash and cash equivalents, end of period	$ 3,783	$ 4,028	$ 1,737	$ 2,136	$ 1,191	$ 2,442	$ 223	$ 2,841	$ 11,456	$ 2,562
Reconciliation of operating income (loss) to net cash provided by operating activities										
Operating income (loss)	$ (101)	$ (116)	$ (12)	$ (14)	$ (9)	$ (18)	$ (1)	$ (23)	$ (104)	$ (61)
Changes in assets and liabilities:										
Accounts receivable	-	-	-	43	8	35	-	(31)	9,731	-
Accounts payable and accruals	(602)	(1,094)	(33)	(40)	(126)	(244)	(1)	(1,649)	1,318	676
Other	1	1	(1)	(1)	(1)	(1)	-	(1)	(2)	-
Net cash provided by (used for) operating activities	$ (702)	$ (1,209)	$ (46)	$ (12)	$ (128)	$ (228)	$ (2)	$ (1,704)	$ 10,943	$ 615
Cash and cash equivalents as stated in the Combined Statements of Net Position										
Cash/cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash/cash equivalents - unrestricted	3,783	4,028	1,737	2,136	1,191	2,442	223	2,841	11,456	2,562
	$ 3,783	$ 4,028	$ 1,737	$ 2,136	$ 1,191	$ 2,442	$ 223	$ 2,841	$ 11,456	$ 2,562

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2023
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS										
	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	Daggett Solar 2 Project	**Totals**
Cash flows from operating activities											
Receipts from participants	$ 26	$ 6,161	$ 635	$ 1,322	$ 592	$ 23,085	$ 5,568	$ 2,810	$ 4,232	$ 2,587	$ 209,460
Payments to operating managers	(117)	(6,499)	(466)	(1,088)	(788)	(20,549)	(4,756)	(1,568)	(2,946)	(35)	(206,582)
Other disbursements and receipts	-	-	(1)	(1)	(1)	(2)	(1)	(2)	4	286	7,766
Net cash flows provided by (used for) operating activities	(91)	(338)	168	233	(197)	2,534	811	1,240	1,290	2,838	10,644
Cash flows from investing activities											
Interest received on investments	88	80	8	8	20	350	10	22	9	2	2,026
Purchases of investments	(1,955)	-	-	-	-	(23,407)	-	-	-	-	(37,623)
Proceeds from sale/maturity of investments	7,500	-	-	-	-	20,800	-	-	-	-	28,300
Net cash provided by (used for) investing activities	5,633	80	8	8	20	(2,257)	10	22	9	2	(7,297)
Net increase (decrease) in cash and cash equivalents	5,542	(258)	176	241	(177)	277	821	1,262	1,299	2,840	3,347
Cash and cash equivalents, beginning of year	2,161	3,386	1,308	1,107	790	639	1,409	3,371	1,172	-	84,690
Cash and cash equivalents, end of period	$ 7,703	$ 3,128	$ 1,484	$ 1,348	$ 613	$ 916	$ 2,230	$ 4,633	$ 2,471	$ 2,840	$ 88,037
Reconciliation of operating income (loss) to net cash provided by operating activities											
Operating income (loss)	$ (223)	$ (79)	$ (4)	$ (7)	$ (20)	$ (583)	$ (10)	$ (21)	$ (9)	$ (2)	$ (2,480)
Changes in assets and liabilities:											
Accounts receivable	4	-	(119)	-	-	-	-	(625)	293	(286)	6,246
Accounts payable and accruals	128	(259)	291	241	(176)	3,118	822	1,887	1,013	3,126	6,895
Other	-	-	-	(1)	(1)	(1)	(1)	(1)	(7)	-	(17)
Net cash provided by (used for) operating activities	$ (91)	$ (338)	$ 168	$ 233	$ (197)	$ 2,534	$ 811	$ 1,240	$ 1,290	$ 2,838	$ 10,644
Cash and cash equivalents as stated in the Combined Statements of Net Position											
Cash/cash equivalents - restricted	2	-	-	-	25	-	-	-	-	-	27
Cash/cash equivalents - unrestricted	7,701	3,128	1,484	1,348	588	916	2,230	4,633	2,471	2,840	88,010
	$ 7,703	$ 3,128	$ 1,484	$ 1,348	$ 613	$ 916	$ 2,230	$ 4,633	$ 2,471	$ 2,840	$ 88,037

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Ormat Geothermal Energy Project	MWD Small Hydro Project	Pebble Springs Project	Ameresco Chiquita Landfill Gas Project	Don A. Campbell/ Wild Rose I Project	Copper Mountain Solar 3 Project	Columbia 2 Solar Project	Heber 1 Geothermal Project	Kingbird Solar Project	Don A. Campbell II Project
Cash flows from operating activities										
Receipts from participants	$ -	$ 16	$ 11,170	$ 1,304	$ 6,145	$ 31,653	$ 231	$ 12,642	$ 108	$ 4,471
Receipts from sale of oil and gas										
Payments to operating managers	-	(284)	(10,945)	(1,844)	(5,476)	(30,256)	(1,634)	(5,754)	(2,323)	(3,840)
Other disbursements and receipts	-	-	-	6	1,777	-	1,236	(1)	2,142	195
Net cash flows provided by (used for) operating activities	-	(268)	225	(534)	2,446	1,397	(167)	6,887	(73)	826
Cash flows from noncapital financing activities										
Advances (withdrawals) by participants, net	-	-	-	-	-	-	-	-	-	-
Cash flows from investing activities										
Interest received on investments	-	-	61	-	65	53	-	76	-	36
Purchases of investments	-	-	-	-	-	-	-	(15,397)	-	-
Proceeds from sale/maturity of investments	-	-	2,000	-	-	-	-	8,000	-	-
Net cash provided by (used for) investing activities	-	-	2,061	-	65	53	-	(7,321)	-	36
Net increase (decrease) in cash and cash equivalents	-	(268)	2,286	(534)	2,511	1,450	(167)	(434)	(73)	862
Cash and cash equivalents, beginning of year	1,941	1,443	2,962	1,522	2,535	3,831	1,252	7,517	837	1,972
Cash and cash equivalents, end of period	$ 1,941	$ 1,175	$ 5,248	$ 988	$ 5,046	$ 5,281	$ 1,085	$ 7,083	$ 764	$ 2,834
Reconciliation of operating income (loss) to net cash provided by operating activities										
Operating income (loss)	$ -	$ -	$ (55)	$ -	$ (53)	$ (44)	$ -	$ (114)	$ -	$ (34)
Changes in assets and liabilities:										
Accounts receivable	-	(134)	-	7	-	2,097	(90)	-	(60)	-
Accounts payable and accruals	-	(134)	280	(540)	2,498	(655)	(78)	7,002	(14)	860
Other	-	-	-	(1)	1	(1)	1	(1)	1	-
Net cash provided by (used for) operating activities	$ -	$ (268)	$ 225	$ (534)	$ 2,446	$ 1,397	$ (167)	$ 6,887	$ (73)	$ 826
Cash and cash equivalents as stated in the Combined Statements of Net Position										
Cash/cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash/cash equivalents - unrestricted	1,941	1,175	5,248	988	5,046	5,281	1,085	7,083	764	2,834
	$ 1,941	$ 1,175	$ 5,248	$ 988	$ 5,046	$ 5,281	$ 1,085	$ 7,083	$ 764	$ 2,834

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	Springbok I Project	Springbok II Project	Summer Solar Project	Astoria 2 Solar Project	Antelope Big Sky Ranch Project	Antelope DSR I Project	Antelope DSR II Project	Puente Hills Landfill Gas Project	Ormat Nevada Geothermal Project	Ormesa Geothermal Project
Cash flows from operating activities										
Receipts from participants	$ 10,683	$ 13,011	$ 226	$ 245	$ 154	$ -	$ 408	$ 502	$ 31,545	$ 10,929
Receipts from sale of oil and gas										
Payments to operating managers	(11,323)	(13,346)	(2,045)	(5,330)	(2,004)	(3,365)	(391)	(1,923)	(43,871)	(9,786)
Other disbursements and receipts	-	-	1,809	5,173	1,739	4,390	-	(5)	(1)	-
Net cash flows provided by (used for) operating activities	(640)	(335)	(10)	88	(111)	1,025	17	(1,426)	(12,327)	1,143
Cash flows from noncapital financing activities										
Advances (withdrawals) by participants, net	-	-	-	-	-	-	-	-	-	-
Cash flows from investing activities										
Interest received on investments	39	40	-	-	-	-	-	-	129	29
Purchases of investments	-	-	-	-	-	-	-	-	(3,446)	-
Proceeds from sale/maturity of investments	-	-	-	-	-	-	-	-	18,500	-
Net cash provided by (used for) investing activities	39	40	-	-	-	-	-	-	15,183	29
Net increase (decrease) in cash and cash equivalents	(601)	(295)	(10)	88	(111)	1,025	17	(1,426)	2,856	1,172
Cash and cash equivalents, beginning of year	3,843	4,017	1,208	2,906	1,050	2,108	179	4,191	2,772	1,300
Cash and cash equivalents, end of period	$ 3,242	$ 3,722	$ 1,198	$ 2,994	$ 939	$ 3,133	$ 196	$ 2,765	$ 5,628	$ 2,472
Reconciliation of operating income (loss) to net cash provided by operating activities										
Operating income (loss)	$ (33)	$ (32)	$ -	$ -	$ -	$ -	$ -	$ -	$ (179)	$ (27)
Changes in assets and liabilities:										
Accounts receivable	519	795	27	125	(215)	(74)	1	(3,346)	(1,765)	249
Accounts payable and accruals	(1,126)	(1,099)	(37)	(37)	104	1,099	16	1,919	(10,383)	921
Other	-	1	-	-	-	-	-	1	-	-
Net cash provided by (used for) operating activities	$ (640)	$ (335)	$ (10)	$ 88	$ (111)	$ 1,025	$ 17	$ (1,426)	$ (12,327)	$ 1,143
Cash and cash equivalents as stated in the Combined Statements of Net Position										
Cash/cash equivalents - restricted	-	-	-	-	-	-	-	-	-	-
Cash/cash equivalents - unrestricted	3,242	3,722	1,198	2,994	939	3,133	196	2,765	5,628	2,472
	$ 3,242	$ 3,722	$ 1,198	$ 2,994	$ 939	$ 3,133	$ 196	$ 2,765	$ 5,628	$ 2,472

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Combining Statements of Cash Flows
For the Six Months Ended December 31, 2022
(Amounts in Thousands)

	POWER PURCHASE AGREEMENTS									
	ARP Loyalton Biomass Project	Springbok III Project	Whitegrass Geothermal Project	Desert Harvest Project	Roseburg Biomass Project	Red Cloud Wind Project	COSO Project	Star Peak Geothermal Project	Mammoth Casa Diablo IV Energy Project	**Totals**
Cash flows from operating activities										
Receipts from participants	$ 13	$ 5,024	$ 825	$ 1,458	$ 605	$ 26,427	$ 5,238	$ 4,194	$ 1,406	$ 180,633
Receipts from sale of oil and gas										-
Payments to operating managers	(48)	(6,816)	(850)	(1,903)	(356)	(15,967)	(5,924)	(3,355)	(123)	(191,082)
Other disbursements and receipts	-	-	1	-	1	9	10	989	-	19,470
Net cash flows provided by (used for) operating activities	(35)	(1,792)	(24)	(445)	250	10,469	(676)	1,828	1,283	9,021
Cash flows from noncapital financing activities										
Advances (withdrawals) by participants, net	-	-	-	-	-	-	-	-	-	-
Cash flows from investing activities										
Interest received on investments	25	50	-	-	9	69	-	-	-	681
Purchases of investments	(10,752)	-	-	-	-	(18,381)	-	-	-	(47,976)
Proceeds from sale/maturity of investments	10,500	-	-	-	-	5,500	-	-	-	44,500
Net cash provided by (used for) investing activities	(227)	50	-	-	9	(12,812)	-	-	-	(2,795)
Net increase (decrease) in cash and cash equivalents	(262)	(1,742)	(24)	(445)	259	(2,343)	(676)	1,828	1,283	6,226
Cash and cash equivalents, beginning of year	1,885	4,555	1,257	1,250	603	8,089	2,701	-	-	69,726
Cash and cash equivalents, end of period	$ 1,623	$ 2,813	$ 1,233	$ 805	$ 862	$ 5,746	$ 2,025	$ 1,828	$ 1,283	$ 75,952
Reconciliation of operating income (loss) to net cash provided by operating activities										
Operating income (loss)	$ (53)	$ (46)	$ -	$ -	$ (8)	$ (121)	$ (11)	$ -	$ -	$ (810)
Changes in assets and liabilities:										
Accounts receivable	1	-	39	(1,240)	1	-	(5)	(1,676)	(3,267)	(8,011)
Accounts payable and accruals	17	(1,746)	(64)	795	257	10,590	(671)	3,509	4,550	17,833
Other	-	-	1	-	-	-	11	(5)	-	9
Net cash provided by (used for) operating activities	$ (35)	$ (1,792)	$ (24)	$ (445)	$ 250	$ 10,469	$ (676)	$ 1,828	$ 1,283	$ 9,021
Cash and cash equivalents as stated in the Combined Statements of Net Position										
Cash/cash equivalents - restricted	1	-	-	-	31	-	-	-	-	32
Cash/cash equivalents - unrestricted	1,622	2,813	1,233	805	831	5,746	2,025	1,828	1,283	75,920
	$ 1,623	$ 2,813	$ 1,233	$ 805	$ 862	$ 5,746	$ 2,025	$ 1,828	$ 1,283	$ 75,952

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
1160 NICOLE COURT
GLENDORA, CA 91740
(626) 793-9364 – FAX: (626) 793-9461
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MEMO

To: SCPPA Finance Committee

From: Aileen Ma, Chief Financial & Administrative Officer

Date: April 4, 2024

Re: **FY 2023-24 Administrative & General (A&G) Expense Budget to Actual Comparison Report – February 2024**

As of February 29, 2024, total A&G expenditures were $6,055,185 which is $645,553 or 9.6% under the year-to-date budget.

Total Indirect A&G expenditures were $3,337,512 which is $311,962 or 8.5% under budget. The under budget was primarily due to:

- Savings in meeting expenses due to lower than expected number of Member staff attending Working Group meetings in person versus virtually.
- Savings in staff travel for meetings, conferences, and training for both the Glendora and Sacramento offices.
- Lower than anticipated consulting services.
- Timing of expenditures and invoices from vendors and consultants.

Total Direct A&G expenditures were $2,717,673 which is $333,591 or 10.9% under budget. The under budget was primarily due to the timing of expenditures for legal and consulting services and savings in agent billable costs because of personnel vacancy.

Southern California Public Power Authority
FY 2023-24 Adminstrative & General (A&G) Expense Budget to Actual
February 29, 2024

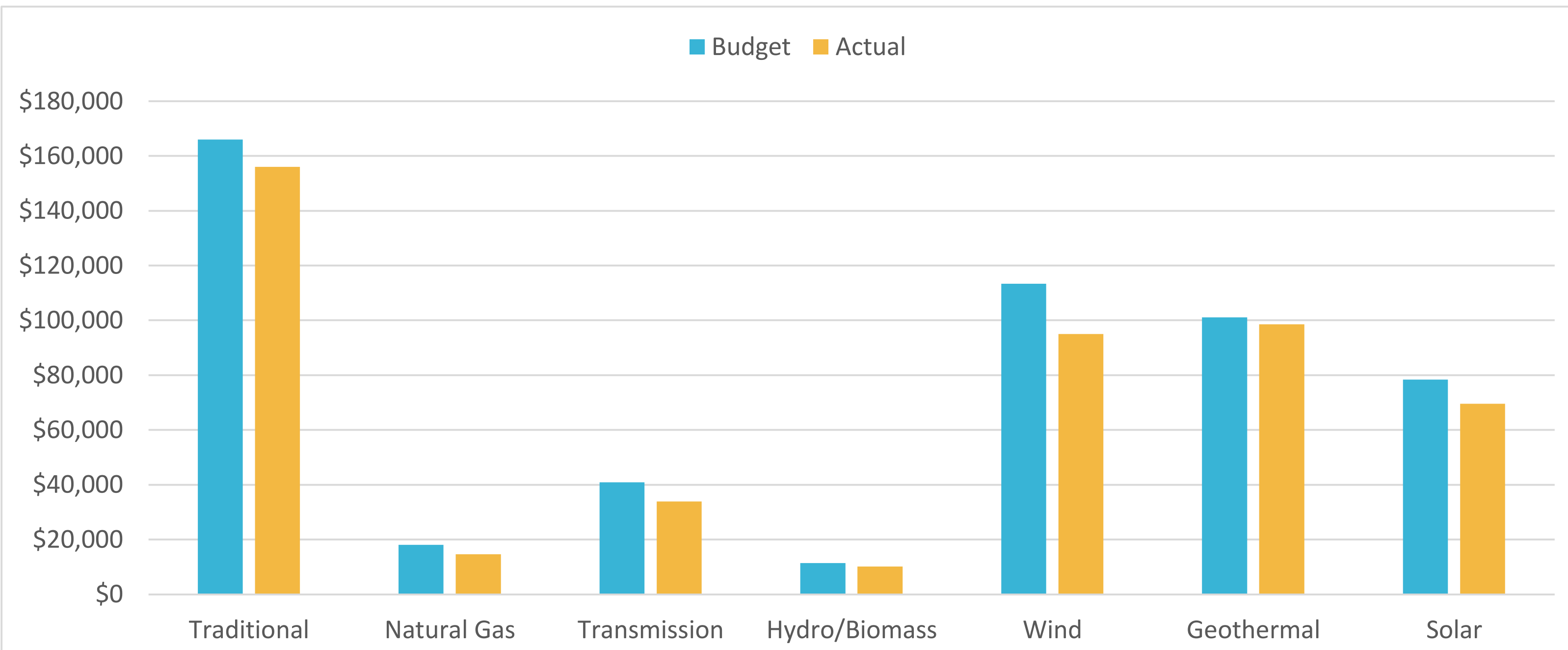
	ANNUAL BUDGET FY 2023-2024	YTD BUDGET 02/29/2024	YTD ACTUAL 02/29/2024	Under / (Over) Budget	% Variance
Salaries	$ 2,907,600	$ 1,938,400	$ 1,913,125	$ 25,275	1.3%
Employee Benefits	742,600	538,380	488,912	49,468	9.2%
Office Building Costs	180,400	98,458	95,693	2,765	2.8%
Office Equipment and IT	135,060	99,504	82,845	16,659	16.7%
Office Expenses	65,100	43,400	24,814	18,586	42.8%
Insurance	150,370	135,170	135,365	(195)	-0.1%
Meeting Expense	54,700	36,468	17,701	18,767	51.5%
Travel and Conferences	55,500	37,000	20,752	16,248	43.9%
Staff Training/Development	53,000	35,332	4,054	31,278	88.5%
Memberships and Dues	23,730	3,370	3,225	145	4.3%
Subscriptions	19,210	12,806	12,633	173	1.3%
Gov't Affairs (Sacramento Office)	175,550	108,659	90,234	18,425	17.0%
Legislative Advocacy	366,200	243,828	241,494	2,334	1.0%
Regulatory Advocacy	200,000	133,332	113,349	19,983	15.0%
General Legal Services	130,000	86,668	58,230	28,438	32.8%
Auditing Services	4,800	4,800	4,800	-	0.0%
Consulting & Other Services	97,350	64,898	9,099	55,799	86.0%
Financial Advisor	90,000	60,000	52,500	7,500	12.5%
Budget Contingency	136,280	-	-	-	0.0%
Subtotal	**$ 5,587,450**	**$ 3,680,473**	**$ 3,368,823**	**$ 311,650**	**8.5%**
Glendora Project Accounting - Direct A&G	(46,500)	(31,000)	(31,312)	312	-1.0%
TOTAL INDIRECT A&G	**$ 5,540,950**	**$ 3,649,473**	**$ 3,337,512**	**$ 311,962**	**8.5%**
Outside Counsels	$ 434,500	$ 289,668	$ 175,489	$ 114,180	39.4%
Auditing Services	351,200	351,200	351,200	-	0.0%
Consulting & Other Services	165,500	110,332	16,070	94,262	85.4%
Project Travel Costs	17,000	11,332	8,761	2,571	22.7%
WREGIS Fees	15,550	10,366	4,581	5,785	55.8%
Agent Billable Costs	2,911,700	1,941,133	1,869,106	72,027	3.7%
Trustee Fees	305,600	203,733	158,654	45,079	22.1%
Rating Agency Fees	129,500	102,500	102,500	-	0.0%
Subtotal	**$ 4,330,550**	**$ 3,020,264**	**$ 2,686,361**	**$ 333,903**	**11.1%**
Glendora Project Accounting	46,500	31,000	31,312	(312)	-1.0%
TOTAL DIRECT A&G	**$ 4,377,050**	**$ 3,051,264**	**$ 2,717,673**	**$ 333,591**	**10.9%**
TOTAL A&G EXPENSES	**$ 9,918,000**	**$ 6,700,737**	**$ 6,055,185**	**$ 645,553**	**9.6%**

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

($000s)

Project Type	Budget	Actual	Difference	%
Traditional	$ 165,956	$ 156,049	$ (9,907)	-6%
Natural Gas	$ 18,025	$ 14,577	$ (3,448)	-19%
Transmission	$ 40,932	$ 33,916	$ (7,016)	-17%
Hydro/Biomass	$ 11,394	$ 10,131	$ (1,263)	-11%
Wind	$ 113,370	$ 94,997	$ (18,373)	-16%
Geothermal	$ 101,130	$ 98,533	$ (2,597)	-3%
Solar	$ 78,379	$ 69,565	$ (8,814)	-11%
Total	**$ 529,186**	**$ 477,767**	**$ (51,419)**	**-10%**



SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Traditional Projects

Apex Combined Cycle	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Capital Improvements	Fuel	Transmission	Insurance	Net Debt Service	Taxes	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 150	$ 90	$ 15,984	$ 4,944	$ 33,711	$ 7,668	$ 252	$ 10,470	$ 624	$ 73,893	1,347,890	$ 54.82
	YTD Actual	$ 102	$ 88	$ 13,847	$ 2,692	$ 33,711	$ 7,877	$ 376	$ 10,141	$ 662	$ 69,495	1,294,238	$ 53.70
	Variance	$ (48)	$ (2)	$ (2,137)	$ (2,252)	$ -	$ 209	$ 124	$ (329)	$ 38	**$ (4,398)**	(53,652)	(1)
	% Variance	-32%	-2%	-13%	-46%	0%	3%	49%	-3%	6%	**-6%**	-4%	-2%

Canyon Power	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Capital Expenses	Non-Operating Income	Variable Fuel	Insurance	Net Debt Service	Taxes	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 108	$ 90	$ 2,400	$ -		$ 4,372	$ -	$ 9,438	$ -	$ 16,408	56,662	$ 289.58
	YTD Actual	$ 116	$ 89	$ (490)	$ 83	$ (46)	$ 4,372		$ 8,691		$ 12,816	61,703	$ 207.70
	Variance	$ 8	$ (1)	$ (2,890)	$ 83	$ (46)	$ -		$ (747)		**$ (3,592)**	5,042	(82)
	% Variance	7%	-1%	-120%			0%		-8%		**-22%**	9%	-28%

Palo Verde	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Renewal & Replacements	APS Admin & General	Other Income	Insurance	Net Investment Income	Taxes	Minimum Cost	MWHs Delivered	
	YTD Budget	$ 120	$ 240	$ 16,746	$ 7,128	$ 3,054	$ -	$ 78	$ (588)	$ 1,500	$ 28,278	952,229	
	YTD Actual	$ 146	$ 248	$ 15,303	$ 8,424	$ 4,239	$ (1,087)	$ 169	$ (754)	$ 1,500	$ 28,188	955,090	
	Variance	$ 26	$ 8	$ (1,443)	$ 1,296	$ 1,185	$ (1,087)	$ 91	$ (166)	$ -	**$ (90)**	2,862	
	% Variance	22%	3%	-9%	18%	39%		116%	28%	0%	**0%**	0%	
	($000s)	Nuclear Fuel	Payments to SRP for Transmission		PV Switchyard O&M,Taxes	Debt Service ANPP Trans. Sys	Debt Service PV Swyd.				Variable Costs	Total Costs	$/MWh
	YTD Budget	$ 6,005	$ -		$ 60	(10)	-				$ 6,056	**$ 34,334**	$ 36.06
	YTD Actual	$ 5,732			$ 76	-	-				$ 5,809	**$ 33,997**	$ 35.60
	Variance	$ (273)	$ -		$ 16	$ 10	$ -				**$ (247)**	**$ (337)**	$ (0)
	% Variance	-5%			27%	-100%					**-4%**	**-1%**	-1%

Magnolia	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Combined Capital Improvements	Major Maintenance	Fuel Transportation & Common Costs	Project A Net Debt Service	Project B Net Debt Service	Fuel	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 204	$ 354	$ 12,252	$ 594	$ 5,286	$ 3,024	$ 8,724	$ 378	$ 4,434	$ 35,250	729,762	$ 48.30
	YTD Actual	$ 156	$ 346	$ 12,394	$ 43	$ 5,286	$ 2,878	$ 7,850	$ 301	4,434	$ 33,686	772,609	$ 43.60
	Variance	$ (48)	$ (8)	$ 142	$ (551)	$ -	$ (146)	$ (874)	$ (77)	$ -	**$ (1,563)**	42,848	$ (4.70)
	% Variance	-24%	-2%	1%	-93%	0%	-5%	-10%	-20%	0%	**-4%**	6%	-10%

San Juan	($000s)	Direct Admin & General	Indirect Admin & General	P&M A&G	Reclamation Trust Contribution	Decommisisoning Trust Contribution	Property Taxes	Insurance	Net Debt Service	Reclamation Study	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 90	$ -	$ 4,578	$ 1,380	$ -	$ -	$ -	$ -	$ 6,072	-	
	YTD Actual	$ 23	$ 87		$ 4,578	$ 1,380		$ 5	$ (19)		$ 6,054	-	
	Variance	$ (1)	$ (3)	$ -	$ -	$ -	$ -	$ 5	$ (19)	$ -	**$ (18)**	-	
	% Variance	-5%	-3%		0%	0%					**0%**		

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Natural Gas Projects

Barnett	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Pasadena Capital (Drilling & Completion)	Net Royalty Gas Tax Income	Investment Income	Cost of Gas	Net Debt Service	Taxes	Total Cost	MMBTUs Delivered	$/MMBtu
	YTD Budget	$ 66	$ 24	$ 378	$ 2	$ -	$ -	$ -	$ 2,016	$ -	$ 2,486		
	YTD Actual	$ 37	$ 12	$ 377	$ (14)	$ -		$ (20)	$ 2,018	$ -	$ 2,411	83,026	$ 29.04
	Variance	$ (29)	$ (12)	$ (1)	$ (16)	$ -	$ -	$ (20)	$ 2		**$ (75)**		
	% Variance	-44%	-48%	0%	-724%				0%		**-3%**		

Pinedale	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Capital Improvements	Net Royalty Gas Tax Income	Net Oil Income	Cost of Gas	Net Debt Service	Taxes	Total Cost	MMBTUs Delivered	$/MMBtu
	YTD Budget	$ 126	$ 12	$ 1,506	$ 54	$ 318	$ (432)	$ -	$ 852	$ 1,152	$ 3,588		
	YTD Actual	$ 133	$ 13	$ 1,562	$ (3)	$ (4,214)	$ (397)	$ 4,041	$ 865	$ 508	$ 2,508	995,061	$ 2.52
	Variance	$ 7	$ 1	$ 56	$ (57)	$ (4,532)	$ 35	$ 4,041	$ 13	$ (644)	**$ (1,081)**		
	% Variance	5%	6%	4%	-105%	-1425%	-8%		1%	-56%	**-30%**		

Prepay	($000s)	Direct Admin & General	Indirect Admin & General	O&M	Capital Improvements	Net Royalty Gas Tax Income	Net Oil Income	Cost of Gas	Net Debt Service	Taxes	Total Cost	MMBTUs Delivered	$/MMBtu
	YTD Budget	$ 48	$ 108	$ -	$ -	$ -	$ -	$ 10,700	$ -	$ -	$ 10,856	1,665,493	
	YTD Billed	$ 48	$ 108					$ 11,795	$ -		$ 11,951		
	YTD Actual	$ 153	$ 105					$ 9,400			$ 9,658	1,961,387	$ 4.92
	Variance	$ 105	$ (3)					$ (2,395)			**$ (2,293)**		
	% Variance	220%	-3%					-20%			**-19%**		

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Transmission Projects

Southern Transmission System	($000s)	Direct Admin & General	Indirect Admin & General	IPA Billings	Non-Operating Income	STS Renewal Billing	Capital Improvements	Net Debt Service	Taxes	Total Cost
	YTD Budget	$ 144	$ 186	$ 18,000	$ -	$ 6	$ -	$ 15,684	$ -	$ 34,020
	YTD Actual	$ 126	$ 180	$ 12,386	$ (0)	$ 6		$ 14,785	$ -	$ 27,483
	Variance	$ (18)	$ (6)	$ (5,614)				$ (899)		**$ (6,537)**
	% Variance	-12%	-3%	-31%				-6%		**-19%**

Mead-Adelanto	($000s)	Direct Admin & General	Indirect Admin & General	O&M A	Insurance Reimbursement	Non-Operating Income	Capital Improvements	Net Debt Service	Taxes	Total Cost
	YTD Budget	$ 60	$ 18	$ 1,416	$ -	$ -	$ 768	$ (24)	$ 102	$ 2,340
	YTD Actual	$ 50	$ 18	$ 1,568	$ -	$ (1)	$ 768	$ (50)	$ 82	$ 2,436
	Variance	$ (10)	$ 0	$ 152			$ -	$ (26)	$ (20)	**$ 96**
	% Variance	-16%	1%	11%			0%	106%	-20%	**4%**

Mead-Adelando (LADWP)	($000s)	Direct Admin & General	Indirect Admin & General	O&M A	Working Capital	Non-Operating Income	Capital Improvements	Net Debt Service	Taxes	Total Cost
	YTD Budget	$ 30	$ 6	$ 366	$ -	$ -	$ 198	$ 1,350	$ 48	$ 1,998
	YTD Actual	$ 19	$ 4	$ 404	$ -	$ -	$ 198	$ 1,328	$ 33	$ 1,986
	Variance	$ (11)	$ (2)	$ 38	$ -	$ -	$ -	$ (22)	$ (15)	**$ (12)**
	% Variance	-35%	-27%	10%			0%	-2%	-31%	**-1%**

Mead-Phoenix	($000s)	Direct Admin & General	Indirect Admin & General	O&M A	O&M B	O&M C	Capital Improvements	Debt Service	Taxes	Total Cost
	YTD Budget	$ 24	$ 12	$ 270	$ 90	$ 204	$ 282	$ (30)	$ 126	$ 978
	YTD Actual	$ 22	$ 4	$ 214	$ 66	$ 150	$ 103	$ (55)	$ 81	$ 585
	Variance	$ (2)	$ (8)	$ (56)	$ (24)	$ (54)	$ (179)	$ (25)	$ (45)	**$ (393)**
	% Variance	-10%	-66%	-21%	-27%	-26%	-63%	83%	-36%	**-40%**

Mead-Phoenix (LADWP)	($000s)	Direct Admin & General	Indirect Admin & General	O&M A	Working Capital	O&M C	Capital Improvements	Net Debt Service	Taxes	Total Cost
	YTD Budget	$ 30	$ 6	$ 174	$ -	$ 72	$ 96	$ 1,092	$ 126	$ 1,596
	YTD Actual	$ 21	$ 4	$ 135	$ -	$ 54	$ 65	$ 1,059	$ 88	$ 1,425
	Variance	$ (9)	$ (2)	$ (39)	$ -	$ (18)	$ (31)	$ (33)	$ (38)	**$ (171)**
	% Variance	-30%	-40%	-23%		-25%	-32%	-3%	-30%	**-11%**

SCPPA

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Hydro/Landfill Gas/Biomass Projects

MWD	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	Scheduling	ISO Charges	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 12	$ -	$ -	$ 228	$ 72	$ -	$ -	$ 312	4,200	$ 74.29
	YTD Actual	$ 11	$ 3	$ -	$ 329	$ 70	$ -	$ (6)	$ 406	6,007	$ 67.61
	Variance	$ (1)	$ 3		$ 101	$ (2)			**$ 94**	1,807	(7)
	% Variance	-8%			44%	-3%			**30%**	43%	-9%

Tieton	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	BWP Project Manager	Non-Operating Income	Net Debt Service	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 60	$ 24	$ 1,146	$ -	$ 60	$ -	$ 1,356	$ 2,646	24,000	$ 110.25
	YTD Actual	$ 62	$ 21	$ 388		$ 225	$ (2)	$ 1,284	$ 1,979	21,996	$ 89.97
	Variance	$ 2	$ (3)	$ (758)		$ 165	$ (2)	$ (72)	**$ (667)**	(2,004)	(20)
	% Variance	4%	-11%	-66%		276%		-5%	**-25%**	-8%	-18%

Chiquita Canyon	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	Scheduling Fees	ISO Charges	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 6	$ 18	$ -	$ 1,080	$ -	$ -	$ -	$ 1,104	16,591	$ 66.54
	YTD Actual	$ 11	$ 17	$ -	$ 1,115	$ -	$ -	$ (6)	$ 1,136	16,966	$ 66.97
	Variance	$ 5	$ (1)		$ 35				**$ 32**	375	0
	% Variance	82%	-6%		3%				**3%**	2%	1%

Puente Hills	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	Scheduling Fees	ISO Charges	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 6	$ 126	$ -	$ 6,510	$ -	$ -	$ -	$ 6,642	81,409	$ 81.59
	YTD Actual	$ 14	$ 121	$ -	$ 6,016	$ -	$ -	$ (23)	$ 6,128	75,205	$ 81.49
	Variance	$ 8	$ (5)		$ (494)				**$ (514)**	(6,204)	(0)
	% Variance	136%	-4%		-8%				**-8%**	-8%	0%

Loyalton	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	Scheduling Fees	Interest Received	Reserves	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 18	$ -	$ -	$ -	$ -	$ -	$ -	$ 18	-	
	YTD Actual	$ 41	$ 0	$ -	$ -	$ -	$ (223)	$ -	$ (181)	-	
	Variance	$ 23	$ 0	$ -	$ -	$ -	$ (223)	$ -	**$ (199)**	-	
	% Variance	129%							**-1107%**		

Roseburg	($000s)	Direct Admin & General	Indirect Admin & General	Capital & Operating Expense	PPA Payments	Scheduling Fees	Net Cost Recovery	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 18	$ 6	$ -	$ 648	$ -	$ -	$ -	$ 672	14,023	$ 47.92
	YTD Actual	$ 16	$ 8	$ -	$ 659	$ -	$ -	$ (20)	$ 663	23,073	$ 28.72
	Variance	$ (2)	$ 2		$ 11		$ -		**$ (9)**	9,050	(19)
	% Variance	-12%	28%		2%				**-1%**	65%	-40%

SCPPA Quarterly Budget Comparisons

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Wind Projects

Linden	($000s)	Direct Admin & General	Indirect Admin & General	Project Manager	O&M	Transmisson/ Exchange	BPA Wind Integration	BPA Generation Imbalance Charge	Lease Expense	Insurance	Net Debt Service	Property Tax	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 72	$ 18	$ 48	$ 876	$ 1,602	$ 318	$ -	$ 300	$ 84	$ 4,428	$ 300	$ 8,046	66,685	$ 120.66
	YTD Actual	$ 79	$ 18	$ 63	$ 841	$ 1,654	$ 245	$ (34)	$ 303	$ 88	$ 4,245	$ 146	$ 7,648	50,882	$ 150.31
	Variance	$ 7	$ (0)	$ 15	$ (35)	$ 52	$ (73)	$ (34)	$ 3	$ 4	$ (183)	$ (154)	**$ (398)**	(15,803)	30
	% Variance	10%	-3%	31%	-4%	3%	-23%		1%	4%	-4%	-51%	**-5%**	-24%	25%

Milford I	($000s)	Direct Admin & General	Indirect Admin & General	Excess Energy	O&M	Transmisson/ Exchange	BPA Wind Integration	LADWP Project Manager	Environmental Attributes	Property Tax & Insurance	Net Debt Service (On Prepay)	Non-Operating Income	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 54	$ 42	$ 4,884	$ -	$ -	$ -	$ 18	$ 3,180	$ 1,704	$ 7,146	$ -	$ 17,028	202,179	$ 84.22
	YTD Actual	$ 62	$ 40	$ 1,429				$ 24	$ 2,181	$ 1,611	$ 6,899	$ (2)	12,245	136,400	$ 89.77
	Variance	$ 8	$ (2)	$ (3,455)				$ 6	$ (999)	$ (93)	$ (247)		**$ (4,783)**	(65,779)	6
	% Variance	15%	-4%	-71%				35%	-31%	-5%	-3%		**-28%**	-33%	7%

Milford II	($000s)	Direct Admin & General	Indirect Admin & General	Excess Energy	O&M	Transmisson/ Exchange	BPA Wind Integration	LADWP Project Manager	Environmental Attributes	Taxes/ Insurance	Net Debt Service (On Prepay)	Property Tax	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 60	$ 18	$ 270	$ -	$ -	$ -	$ 18	$ 2,076	$ 786	$ 4,986		$ 8,214	97,129	$ 84.57
	YTD Actual	$ 58	$ 18	$ -	$ -	$ -	$ -	$ 27	$ 1,448	$ 744	$ 4,848		$ 7,142	66,473	$ 107.44
	Variance	$ (2)	$ 0	$ (270)				$ 9	$ (628)	$ (42)	$ (138)		**$ (1,072)**	(30,656)	23
	% Variance	-4%	0%	-100%				51%	-30%	-5%	-3%		**-13%**	-32%	27%

Pebble Springs	($000s)	Direct Admin & General	Indirect Admin & General	PPA Payments	LADWP Project Manager	Transmisson/ Exchange	Avangrid Wind Integration	Transmission &Generation Imbalance Charge	Environmental Attributes	Reserves	Interest Received	Property Tax	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 48	$ 7,380	$ 18	$ 1,614	$ 750	$ 750	$ -	$ -	$ -	$ -	$ 10,584	103,754	$ 102.01
	YTD Actual	$ 27	$ 44	$ 5,784	$ 18	$ 1,494	$ 703	$ 784			$ (154)		8,699	80,236	$ 108.42
	Variance	$ 3	$ (4)	$ (1,596)	$ (0)		$ (47)			$ -	$ (154)		**$ (1,885)**	(23,518)	6
	% Variance	11%	-8%	-22%	-1%		-6%						**-18%**	-23%	6%

Red Cloud	($000s)	Direct Admin & General	Indirect Admin & General	PPA Payments	LADWP Project Manager	Transmisson/ Exchange	Test Energy	Transmission &Generation Imbalance Charge	Environmental Attributes	Reserves	Interest Received	Property Tax	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 60	$ 27,600	$ 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,702	$ 673,155	$ 41.15
	YTD Actual	$ 29	$ 61	$ 21,017	$ 42	$ -	$ -	$ -	$ -	$ -	$ (583)	$ -	$ 20,567	$ 509,434	$ 40.37
	Variance	$ 5	$ 1	$ (6,583)	$ 24	$ -	$ -	$ -			$ (583)		**$ (7,135)**	(163,721)	(1)
	% Variance	22%	1%	-24%	135%								**-26%**	-24%	-2%

Windy Flats	($000s)	Direct Admin & General	Indirect Admin & General	Excess Energy	O&M	Transmisson/ Exchange	BPA Wind Integration	BPA Generation Imbalance Charge	Environmental Attributes	Project Manager	Net Debt Service	Non-Operating Income	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 72	$ 96	$ 1,626	$ 8,292	$ 5,208	$ 4,836	$ -	$ 2,016	$ 30	$ 19,620	$ -	$ 41,796	335,899	$ 124.43
	YTD Actual	$ 75	$ 92	$ 1,327	$ 8,598	$ 4,557	$ 4,776	$ -	$ 1,637	$ 22	$ 17,614	$ (0)	38,697	271,551	$ 142.50
	Variance	$ 3	$ (4)	$ (299)	$ 306	$ (651)	$ (60)		$ (379)	$ (8)	$ (2,006)		**$ (3,099)**	(64,348)	18
	% Variance	4%	-4%	-18%	4%	-13%	-1%		-19%	-28%	-10%		**-7%**	-19%	15%

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Geothermal Projects

Mammoth Casa Diablo IV	($000s)	Direct Admin & General	Indirect Admin & General	Excess Energy	Working Capital	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 12	$ 54	$ -	$ -	$ 4,896	$ -	$ 4,962	$ 75,328	$ 65.87
	YTD Actual	$ 13	$ 53	$ -	$ -	$ 4,437	$ (9)	$ 4,495	69,608	$ 64.57
	Variance	$ 1	$ (1)	$ -	$ -	$ (459)	$ (9)	**$ (467)**	(5,720)	(1)
	% Variance	9%	-1%			-9%		**-9%**	-8%	-2%

Coso	($000s)	Direct Admin & General	Indirect Admin & General	Excess Energy	Working Capital	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 6	$ 84	$ 24	$ -	$ 5,454	$ -	$ 5,568	79,008	$ 70.47
	YTD Actual	$ 12	$ 85	$ -	$ -	$ 5,200	$ (10)	$ 5,287	74,273	$ 71.18
	Variance	$ 6	$ 1			$ (254)		**$ (281)**	(4,735)	1
	% Variance	101%	1%			-5%		**-5%**	-6%	1%

DAC I	($000s)	Direct Admin & General	Indirect Admin & General	LADWP Project Manager	Non-Operating Income (PEC Sale)	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 18	$ 18	$ -	$ 6,054	$ -	$ 6,114	$ 61,162	$ 99.96
	YTD Actual	$ 25	$ 17	$ 22	$ -	$ 5,753	$ (129)	$ 5,689	60,572	$ 93.92
	Variance	$ 1	$ (1)	$ 4	$ -	$ (301)	$ (129)	**$ (425)**	(590)	(6)
	% Variance	5%	-6%	23%		-5%		**-7%**	-1%	-6%

DAC II	($000s)	Direct Admin & General	Indirect Admin & General	LADWP Project Manager	Non-Operating Income (PEC Sale)	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 12	$ 18	$ -	$ 4,308	$ -	$ 4,362	53,020	$ 82.27
	YTD Actual	$ 28	$ 10	$ 20	$ -	$ 3,908	$ (80)	$ 3,885	49,410	$ 78.63
	Variance	$ 4	$ (2)	$ 2		$ (400)	$ (80)	**$ (477)**	(3,610)	(4)
	% Variance	17%	-21%	9%		-9%		**-11%**	-7%	-4%

Heber I	($000s)	Direct Admin & General	Indirect Admin & General	LADWP Project Manager	Working Capital	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 72	$ 18	$ -	$ 11,742	$ -	$ 11,856	$ 132,249	$ 89.65
	YTD Actual	$ 25	$ 73	$ 20	$ -	$ 14,903	$ (466)	$ 14,554	168,282	$ 86.49
	Variance	$ 1	$ 1	$ 2		$ 3,161	$ (466)	**$ 2,698**	36,034	(3)
	% Variance	3%	1%	12%		27%		**23%**	27%	-4%

NNGP	($000s)	Direct Admin & General	Indirect Admin & General	LADWP Project Manager	Working Capital	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 120	$ 36	$ -	$ 53,616	$ -	$ 53,796	710,107	$ 75.76
	YTD Actual	$ 32	$ 118	$ 36	$ -	$ 53,352	$ (104)	$ 53,434	714,194	$ 74.82
	Variance	$ 8	$ (2)	$ 0	$ -	$ (264)	$ (104)	**$ (362)**	4,087	(1)
	% Variance	32%	-2%	1%		0%		**-1%**	1%	-1%

Ormesa	($000s)	Direct Admin & General	Indirect Admin & General	LADWP Project Manager	Working Capital	PPA Payments	Interest Received	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 48	$ 12	$ -	$ 10,254	$ -	$ 10,338	$ 132,702	$ 77.90
	YTD Actual	$ 30	$ 49	$ 21	$ -	$ 9,660	$ (61)	$ 9,699	125,284	$ 77.42
	Variance	$ 6	$ 1	$ 9	$ -	$ (594)	$ (61)	**$ (639)**	(7,418)	(0)
	% Variance	27%	3%	72%		-6%		**-6%**	-6%	-1%

Star Peak	($000s)	Direct Admin & General	Indirect Admin & General	Delay Damages	Interest Received	PPA Payments	Excess Monthly Generation	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 36	$ -	$ -	$ 3,162	$ 150	$ 3,372	45,001	$ 74.93
	YTD Actual	$ 54	$ 34	$ (627)	$ (21)	$ 1,610	$ -	$ 1,050	29,599	$ 35.48
	Variance	$ 30	$ (2)	$ (627)	$ (21)	$ (1,552)	$ (150)	**$ (2,322)**	(15,402)	(39)
	% Variance	124%	-5%			-49%	-100%	**-69%**	-34%	-53%

WhiteGrass No. 1	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Delay Damages	PPA Payments	Excess Monthly Generation	Total Cost	MWHs Delivered	$/MWh
	YTD Budget	$ 24	$ 6	$ -	$ -	$ 642	$ 90	$ 762	$ 9,490	$ 80.30
	YTD Actual	$ 24	$ 8	$ (5)	$ (119)	$ 530	$ -	$ 439	10,180	$ 43.11
	Variance	$ (0)	$ 2	$ (5)	$ (119)	$ (112)	$ (90)	**$ (323)**	690	(37)
	% Variance	0%	29%			-17%	-100%	**-42%**	7%	-46%

SCPPA Quarterly Budget Comparisons

Quarter Ending December 31, 2023

Solar Projects

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Big Sky Ranch	**YTD Budget**	$ 6	$ 42		$ 18	$ 1,926	$ 1,992	27,444	$ 72.59
	YTD Actual	$ 11	$ 39	$ (9)	$ 18	$ 1,597	$ 1,656	22,413	$ 73.88
	Variance	$ 5	$ (3)		$ 0	$ (329)	**$ (336)**	(5,031)	1
	% Variance	82%	-8%		1%	-17%	**-17%**	-18%	2%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Working Capital	PPA Payments	Total Cost	MWHs REC Quantity	$/MWh
Desert Harvest II	**YTD Budget**	$ 6	$ 12	$ -	$ -	$ 1,428	$ 1,446	91,980	$ 15.72
	YTD Actual	$ 12	$ 14	$ (7)	$ -	$ 1,074	$ 1,093	70,458	$ 15.52
	Variance	$ 6	$ 2			$ (354)	**$ (353)**	(21,522)	(0)
	% Variance	95%	20%			-25%	**-24%**	-23%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
DSR I	**YTD Budget**	$ 6	$ 66		$ 18	$ 3,534	$ 3,624	64,547	$ 56.15
	YTD Actual	$ 12	$ 66	$ (18)	$ 20	$ 2,740	$ 2,819	50,984	$ 55.30
	Variance	$ 6	$ (0)		$ 2	$ (794)	**$ (805)**	(13,563)	(1)
	% Variance	101%	0%		9%	-22%	**-22%**	-21%	-2%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
DSR II	**YTD Budget**	$ 6	$ 18		$ -	$ 378	$ 402	6,802	$ 59.10
	YTD Actual	$ 10	$ 18	$ (1)	$ -	$ 315	$ 341	5,858	$ 58.28
	Variance	$ 4	$ 0	$ (1)	$ -	$ (63)	**$ (61)**	(943)	(1)
	% Variance	62%	2%			-17%	**-15%**	-14%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Astoria 2	**YTD Budget**	$ 6	$ 96	$ -	$ -	$ 4,224	$ 4,326	67,014	$ 64.55
	YTD Actual	$ 12	$ 94	$ (14)	$ (11)	$ 3,832	$ 3,912	58,681	$ 66.67
	Variance	$ 6	$ (2)		$ (11)	$ (392)	**$ (414)**	(8,333)	2
	% Variance	100%	-2%			-9%	**-10%**	-12%	3%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Columbia Two	**YTD Budget**	$ 6	$ 24	$ -	$ 18	$ 1,470	$ 1,518	21,024	$ 72.20
	YTD Actual	$ 12	$ 23	$ (12)	$ 18	$ 1,260	$ 1,301	18,029	$ 72.17
	Variance	$ 6	$ (1)	$ (12)	$ 0	$ (210)	**$ (217)**	(2,995)	(0)
	% Variance	105%	-2%		1%	-14%	**-14%**	-14%	0%

	($000s)	Direct Admin & General	Indirect Admin & General	LADWP O&M	Interest Received	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Copper Mountain 3	**YTD Budget**	$ 60	$ 84	$ 18	$ -	$ 29,358	$ 29,520	306,600	$ 96.28
	YTD Actual	$ 33	$ 82	$ 41	$ (206)	$ 28,086	$ 28,038	293,328	$ 95.58
	Variance	$ (27)	$ (2)	$ 23	$ (206)	$ (1,272)	**$ (1,482)**	(13,272)	(1)
	% Variance	-45%	-2%	129%		-4%	**-5%**	-4%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	Scheduling Coordinator	Working Capital	PPA Payments (PV & BESS)	Total Cost	MWHs Delivered (PV)	$/MWh
Daggett Solar + Storage	**YTD Budget**	$ 5	$ -	$ 40	$ 170	$ 2,372	$ 2,587	$ 64,331	$ 40.21
	YTD Actual	$ 5	$ -	$ 43	$ 168	$ 304	$ 519	3,497	$ 148.47
	Variance	$ (0)	$ -	$ 3		$ (2,068)	**$ (2,068)**	(60,834)	108
	% Variance	-2%		8%		-87%	**-80%**	-95%	269%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Kingbird B	**YTD Budget**	$ 6	$ 36		$ 48	$ 1,986	$ 2,076	28,908	$ 71.81
	YTD Actual	$ 11	$ 35	$ (4)	$ 47	$ 1,851	$ 1,940	26,929	$ 72.05
	Variance	$ 5	$ (1)	$ (4)	$ (1)	$ (135)	**$ (136)**	(1,979)	0
	% Variance	78%	-4%		-1%	-7%	**-7%**	-7%	0%

	($000s)	Direct Admin & General	Indirect Admin & General	LADWP O&M	Interest Received	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Springbok I	**YTD Budget**	$ 24	$ 24	$ 18	$ -	$ 10,410	$ 10,476	151,767	$ 69.03
	YTD Actual	$ 28	$ 23	$ 21	$ (101)	$ 9,614	$ 9,585	140,140	$ 68.39
	Variance	$ 4	$ (1)	$ 3	$ (101)	$ (796)	**$ (891)**	(11,627)	(1)
	% Variance	18%	-4%	14%		-8%	**-9%**	-8%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	LADWP O&M	Interest Received	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Springbok II	**YTD Budget**	$ 24	$ 30	$ 18	$ -	$ 12,144	$ 12,216	207,065	$ 59.00
	YTD Actual	$ 27	$ 27	$ 21	$ (116)	$ 11,268	$ 11,227	192,120	$ 58.44
	Variance	$ 3	$ (3)	$ 3	$ (116)	$ (876)	**$ (989)**	(14,945)	(1)
	% Variance	12%	-11%	18%		-7%	**-8%**	-7%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	LADWP O&M	Interest Received	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Springbok III	**YTD Budget**	$ 24	$ 12	$ 18	$ -	$ 6,144	$ 6,198	118,260	$ 52.41
	YTD Actual	$ 33	$ 14	$ 22	$ (79)	$ 5,647	$ 5,637	108,665	$ 51.87
	Variance	$ 9	$ 2	$ 4	$ (79)	$ (497)	**$ (561)**	(9,595)	(1)
	% Variance	38%	14%	24%		-8%	**-9%**	-8%	-1%

	($000s)	Direct Admin & General	Indirect Admin & General	Interest Received	Scheduling Fees	PPA Payments	Total Cost	MWHs Delivered	$/MWh
Summer	**YTD Budget**	$ 6	$ 42	$ -	$ 18	$ 1,932	$ 1,998	27,672	$ 72.20
	YTD Actual	$ 11	$ 39	$ (12)	$ 18	$ 1,441	$ 1,497	20,223	$ 74.00
	Variance	$ 5	$ (3)	$ (12)	$ 0	$ (491)	**$ (501)**	(7,449)	2
	% Variance	79%	-8%		1%	-25%	**-25%**	-27%	2%

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

2023-24 STRATEGIC PRIORITIES REPORT

April 18, 2024

ADVOCACY

Emphasize the unique needs of Member communities by facilitating proactive advocacy.

Goals	Board Update
OBJECTIVE: Facilitate External and Internal Communication	
Plan the State Capitol Day	The 2024 Public Power Capitol Day was held on Monday, February 5th. Planning and strategy for Capitol Day was informed by SCPPA Government Affairs' strategic planning meeting in December. For Capitol Day, SCPPA Government Affairs organized several meetings, including with the new Assembly Utilities and Energy Committee chair, the Assembly Speaker's chief energy advisor, the Senate Energy Committee's chief consultants, and various legislators and legislative staff. In coordination with SCPPA Members, SCPPA drafted an eight-page Capitol Day white paper on clean energy market issues. SCPPA also organized and hosted a SCPPA Members dinner with over 20 SCPPA representatives. SCPPA has followed up Capitol Day with over 10 meetings with legislative offices (including the Senate pro Tem's chief energy advisor and members of the energy committees) that we were not able to meet with at Capitol Day due to time constraints.
Plan the Federal Fly-In	The 2024 APPA Legislative Rally/SCPPA Fly-in was held in Washington, D.C. from February 26-28th. Planning and strategy for the event was informed by SCPPA Government Affairs' strategic planning meeting in December. For the event, SCPPA organized over 15 scheduled meetings with federal legislative and agency offices. SCPPA drafted issue papers on clean energy policy (including direct pay), transformers, advanced refunding bonds, and nuclear. SCPPA also organized and hosted a SCPPA dinner for over 20 SCPPA representatives.
Plan the Policy Staff Tour	SCPPA is working with SCPPA Members to organize the SCPPA Policy Staff Tour, which is set for July 10-12. The theme of the tour will be transmission (e.g., CAISO issues, non-CAISO issues, non-transmission solutions). Preliminary plans have stops at the LADWP energy control center, Burbank, Glendale, Pasadena, and Nevada (Hoover, Copper Mountain, Marketplace).
Proactively identify opportunities to have SCPPA Members meet with key regulatory and legislative staff and policymakers on key issues	SCPPA has been organizing reoccurring meetings with California Energy Commission and Vice Chair Gunda, which started in December 2023. On January 10, 2024, SCPPA coordinated a trip for Vice Chair Gunda, and SB 100 lead staff Dr. Liz Gill, to visit with SCPPA Members. Principles and resource planning staff from SCPPA joined and toured Burbank and Glendale facilities. On March 19th, SCPPA coordinated a POU meeting with Vice Chair Gunda's chief of staff, senior advisors, and SB 100 report staff. NCPA, CMUA, and SMUD also participated in the meeting. The agenda included brief updates on RPS long term commitment and resource adequacy issues discussed at previous meetings. The agenda included longer discussions on (1) regional coordination, (2) SB 100 report's analysis on reliability and emerging

	technologies, and (3) better funding coordination. Follow up is occurring in sub-meetings with POUs and CEC staff. We are aiming for our next reoccurring POU meeting with Vice Chair Gunda in May. On March 7, 2024, SCPPA's RWG hosted guest presenters from the South Coast Air Quality Management District (SCAQMD) to discuss current and upcoming rulemakings regarding air quality from stationary sources and associated fees. SCAQMD is currently focused on developing the regulatory framework for collecting nonattainment fees. SCPPA discussed and plans to engage more heavily with SCAQMD when they begin a public process in about 2 years to identify how to direct funding back into the communities. On April 2, 2024, SCPPA and SCPPA Member subject matter experts met with the chief consultant of the Assembly Utilities and Energy Committee. SCPPA Members shared information about the CAISO's resource adequacy program, limitations of that program, and the effect of CAISO and CPUC policies on the resource adequacy market. Subject matter experts also discussed the costs and consequences of the constrained RA market and the impact of recent state policy decisions on addressing reliability issues.
Plan Special Educational Events (e.g., Workshops for SCPPA Members and Tours for Policymakers), When Appropriate	SCPPA Government Affairs held special educational events in December (SoCalGas Angeles Link tour and NCPA Lodi Energy Center tour). SCPPA events in Q1 of 2024 were focused on advocacy (Capitol Day and APPA Rally/SCPPA Fly-in). SCPPA is exploring potential special educational events in Q2 of 2024.
Grow SCPPA's External Affairs Efforts to Promote SCPPA and Its Members	SCPPA has been posting and sharing stories about SCPPA and SCPPA Members on Twitter. As time permits, SCPPA is looking for opportunities to grow external affairs efforts.
OBJECTIVE: Champion POU Issues	
Monitor and Advocate on Regulatory Issues	**California Air Resources Board:** *Cap-and-Trade* - Cap-and-Trade - On June 14, 2023 CARB kicked off a series of informal workshops leading up to the Cap-and-Trade rulemaking. SCPPA provided support to the JUG comments that were submitted on July 7, 2023. Following an informal rulemaking workshop on July 27, SCPPA submitted comments on August 17 primarily expressing concerns over CARB requiring POU consignment and reducing allowance allocations. SCPPA also assisted in the development of comments that were submitted by CMUA and the JUG. On October 5, CARB hosted another informal workshop on allowance allocation. Subsequently, SCPPA arranged a meeting with CARB staff and other POU representatives on allowance allocations that took place on October 16. On October 26, 2023 SCPPA submitted written comments focused on protecting POU allowances through 2030. Then, on November 16, CARB hosted a workshop regarding modeling and the potential post-2030. SCPPA contributed to comments submitted on December 15, 2023 by CMUA and the JUG. SCPPA participated in two meetings with the JUG and CARB to discuss utility priority for allowance allocation, on February 27 and March 28, 2024. *Advanced Clean Fleets (ACF)* - SCPPA monitored the final 15-day changes and final approval (by the Office of Administrative Law), making the rule effective October 1, 2023. SCPPA encouraged Members to apply for the Truck Regulatory Implementation Groups (TRIGS) beginning in November, 2023. SCPPA is monitoring and sharing updates on the TRIG meetings, which kicked off on December 6/8. SCPPA continues to provide coverage of materials and trainings offered by CARB for ACF implementation. SCPPA has confirmed with CARB staff that CARB will be amending the ACF rule to accommodate AB 1594 and will be holding workshops on those amendments. SCPPA participated in the first CARB workshop on AB 1594,

	held on March 25, 2024. SCPPA is drafting informal comments to be submitted in April, 2024. _Zero-Emission Forklifts_ - SCPPA Members met with CARB regarding the Zero-Emission Forklift rulemaking on August 15 and 18 to answer CARB's questions about how utilities will plan for the added load required to charge forklift fleets. **California Energy Commission:** _Distributed Electricity Backup Assets (DEBA)_ - SCPPA submitted comments on the draft DEBA program guidelines on August 15, 2023. In addition, SCPPA contributed to CMUA comments that were also submitted August 15th. On September 20th, SCPPA presented a grant funding workshop, including details on applying for DEBA grants. In late 2023, the CEC opened grant applications for the bulk grid assets portion of the DEBA program and early in 2024, SCPPA coordinated with Burbank Water and Power on an application submission on behalf of Magnolia participants. SCPPA also submitted comments on March 21, 2024 on the draft grant solicitation for the distributed energy resources portion of the DEBA program. _Demand Side Grid Support (DSGS)_ - SCPPA coordinated meetings between the DSGS program administrator and participating Members during summer of 2023. SCPPA also submitted comments on the DSGS program and arranged for the CEC to provide program details at a SCPPA Regulatory Working Group meeting. In February 2024, SCPPA participated in joint comments on proposed changes to DSGS for summer 2024. SCPPA advocated for fair treatment of non-CAISO balancing authorities, strong participant eligibility verification requirements, and reasonable caution with respect to V2X applications being included in DSGS. _Power Source Disclosure_ - *The CEC kicked off a new Power Source Disclosure rulemaking to incorporate updates to the Power Content Label (PCL) and include SB 1158 hourly reporting requirements at a workshop on September 26, 2023. SCPPA arranged a meeting with CEC program staff and other POU representatives for October 19, 2023. SCPPA submitted on October 24 requesting that the CEC remove GHGs associated with geothermal generation from the Power Content Label. SCPPA contributed to CMUA comments on October 24th as well. SCPPA arranged a meeting with CEC's Vice Chair Gunda's Chief of Staff on November 2 to further discuss SCPPA's specific request to remove geothermal GHGs. SCPPA clarified and justified this request at a meeting with Vice Chair Gunda in Southern California on January 10, 2024. CEC staff posted updated draft regulatory language in February, 2024 and removed geothermal GHGs from the PCL. SCPPA submitted written comments and contributed to CMUA comments on February 21. SCPPA expressed appreciation to the CEC for removing geothermal GHG emissions from the PCL.* _Title 24_ - SCPPA submitted comments to the CEC on August 9 in response to a workshop held on July 27, 2023 regarding the 2025 Pre-Rulemaking Staff Workshop on Heat Pump Baselines and Photovoltaic System Requirements. _Integrated Energy Policy Report (IEPR)_ - SCPPA submitted comments on the CEC's September 8th workshop on the Potential Growth of Hydrogen on September 22nd that highlighted the opportunities and challenges for hydrogen for the electricity sector and transportation in Southern California. _Clean Transportation Program -_ SCPPA coordinated Joint POU comments following a pre-solicitation workshop to provide input on the development of a

	grant funding opportunity for municipal and government fleets ZEV infrastructure submitted on August 4, 2023. *AB 2127 EV Charging Infrastructure Assessment* - SCPPA contributed to and provided support for CalETC's comment letter regarding the CEC's AB 2127 draft report on September 21, 2023. *Community Energy Resilience Investments (CERI) Program* - SCPPA submitted comments to the CEC on September 29, 2023 in response to a workshop held on September 12, 2023 to provide input on the development of the grant program. In addition, SCPPA arranged for the lead CEC staff of the program to speak at a September 20th joint working group grant funding workshop. The CEC released the grant solicitation for the now-named Community Energy Reliability and Resiliency Investment (CERRI) Program on March 28. SCPPA shared the grant information with Members and is following up on Member questions. *Other Energy Issues* – SCPPA has been holding reoccurring meetings with CEC leadership, including Vice Chair Gunda. This included a January 10th SCPPA tour with Vice Chair Gunda and the lead CEC staffer on the SB 100 report and a March 19th SCPPA-led Joint POU meeting with Com. Gunda's senior staff. SCPPA is also coordinating with LADWP for a presentation at the April 16th CEC SB 100 workshop on non-energy benefits. **California Public Utilities Commission:** *SGIP* – SCPPA led the joint-POU effort to influence the CPUC proceeding to provide $280 million to low-income customers in both IOU and POU territories in the state. SCPPA also contributed to CMUA's comments submitted August 11th regarding the Self-Generation Incentive Program (SGIP) and Heat Pump Water Heater Program Improvements rulemaking. Freight Infrastructure Planning (FIP) - On August 8, September 7, and September 18, SCPPA participated in calls with CPUC staff along with CMUA and NCPA to discuss the role of POUs in the CPUC's FIP. The POUs showed willingness to continue discussions and work alongside the CPUC through the FIP process. Office of Energy Infrastructure Safety: SCPPA participated in the Wildfire Safety Advisory Board's (WSAB) Truckee Donner Public Utilities District visit on October 2nd. SCPPA spent time speaking directly to the WSAB's chair and staff about POUs and their wildfire mitigation plans. **SWRCB:** *Utility Wildfire General Order* - SCPPA coordinated Joint POU comments (submitted July 14, 2023) following the circulation of an administrative draft General Order regarding water quality permitting related to wildfire mitigation and other utility activities. SCPPA provided input on the scope, criteria, and administrative requirements of the draft General Order. **Regionalization/CAISO:** *Governance Pathway Initiative* - SCPPA hosted the Vice President of External Affairs for CAISO at a September 7th meeting to discuss CAISO's perspective of the regulator-led Governance Pathway Initiative. **Grants:** SCPPA Government Affairs worked to amend the current Master Professional Services Agreement with The Ferguson Group to allow SCPPA Members to enter into umbrella task orders for grant writing services – as opposed to entering into individual task orders for specific grants. This will

	streamline the ability for SCPPA Members to use these services. With the amendment in place, SCPPA Government Affairs has been working with several SCPPA Members to enter into umbrella task orders, and many are currently using these task orders to apply for both federal and state grants. **Treasury:** Direct Pay Regulations – SCPPA is working with Congresswoman Julie Chu's office to write a letter to the Treasury requesting that the Inflation Reduction Act's direct pay and domestic content final regulations are workable and provide regulatory certainty and clarity.
Monitor and Advocate on Legislative Issues	**Pole Attachments (AB 2221, Carrillo):** AB 2221 established various shot clock requirements for broadband pole attachments on IOU and POU utility poles. SCPPA is strongly opposed due to worker and public safety issues. SCPPA Government Affairs submitted an opposition letter and lobbied the Democrats and Republicans on the Assembly Utilities and Energy Committee. SCPPA also met with the committee chair prior to the bill's April 3rd hearing. The committee pulled the bill at the beginning of the hearing. It is not clear if the bill will be heard prior to the policy committee deadline at the beginning of May. SCPPA will continue to oppose if the bill is set. **Energy Storage Targets (SB 1508, Stern):** SB 1508 recasts AB 2514 (Skinner, 2010) energy storage targets for IOUs and POUs, which sunset in 2020. The new targets would be for 2028, 2030, and 2035. SCPPA is working on amendments that would exclude POUs since they are now reporting on energy storage goals in their integrated resource plans. **Climate Equity Trust Fund (AB 2329, Muratsuchi):** AB 2329 would establish a framework for the state to direct federal funds and Greenhouse Reduction Funds to spending plans designed to benefit LSE and POU customers. SCPPA's is working on amendments that would (1) authorize funding for clean energy infrastructure projects and (2) require spending plans to be developed in consultation with a POU advisory committee. **County Sealers and Public Agency's EV Chargers (AB 2037, Papan):** AB 2037 would authorize county sealers to inspect a public agency's EV chargers. If a charger is "incorrect" (i.e., it overcharges customers) the bill requires the county sealer to either seize and condemn or tag as "out of order" depending if the charger can – based on the county sealer's judgment – be repaired. The county sealer can also charge an annual registration fee for the cost of inspecting the public agency's chargers. SCPPA is working on amendments that would only authorize a county sealer to place a tag on an incorrect charger explaining to customers why it's incorrect. Additionally, a registration fee would not be authorized if the public agency has processes in place to regularly inspect its chargers. **Biomass Mandate (SB 1062, Dahle):** SB 1062 would require IOUs and POUs with 100,000 more connections to procure an additional 125 MWs collectively of biomass energy from facilities with plans to convert to "advanced bioenergy technology facilities." SCPPA is opposing because of the high costs of the bill on POU customers. **AB 1373 Clean Up (AB 1834, Garcia):** AB 1373 was passed last year to require CAISO POUs to pay a capacity payment when they do not meet their planning reserve margin in a month with the State Reliability Reserve was used. AB 1373 also creates a central procurement program for long lead time resources (mandatory for LSEs, voluntary for POUs). SCPPA and NCPA leading efforts through AB 1834 to make clean up amendments to AB 1373 to avoid unintended consequences.

	Transformer Resolution: SCPPA is working on introducing a resolution in the state legislature urging Congress to fund the DOE to use the Defense Production Act to boost domestic manufacturing of distribution transformers. **Energy Resources Programs Account (ERPA) Surcharge (Governor's Budget Trailer Bill):** The governor is proposing an increase on the ERPA surcharge on retail customers. SCPPA is coordinating with NCPA and CMUA on an "oppose unless amend" strategy to protect ratepayers. **Net Energy Metering (AB 2619, Connolly; AB 2256, Friedman):** Both AB 2619 and AB 2256 would require LSE and POUs to adopt a net energy metering tariff that would, in effect, provide higher subsidies for rooftop solar customers. SCPPA has been educating the authors on POU rooftop solar tariffs. AB 2256 was amended to focus only on LSEs, and AB 2619 will be amended to do the same.
Prepare Issue Papers	SCPPA has developed presentations on the current energy markets and the transformer supply chain crisis, which have been and will continue to be shared with state and federal legislative and regulatory offices. SCPPA also preparing a series of issue papers for Capitol Day (clean energy markets issue paper) and the Federal Fly-In (clean energy, transformers, advanced refunding bonds, and nuclear).
Plan Government Affairs' Strategic Planning Meeting to Set Priorities and Broad Strategies	SCPPA's Government Affairs team held an all-day strategic planning meeting on December 13th with SCPPA's consultants and SCPPA Members to develop legislative and regulatory strategies for 2024. Action items were entered into SCPPA Government Affair's annual goals tracking system and are being incorporated into planning and implementation of advocacy activities.
Seek Board Support through Approval of Guiding Principles	SCPPA Government Affairs developed SCPPA's 2024 Guiding Policy Principles with the Regulatory Working Group and Legislative Working Group and submitted the principles for formal adoption at the February SCPPA Board meeting.

ASSETS

Be trustworthy stewards of public funds through the responsible administration of financial and physical assets and obligations.

Goals	Board Update
OBJECTIVE: Control Project Costs and Optimize Output	
Effectively resolve emergent project issues: ▪ Negotiate new NAESBs for Pinedale and Barnett trading to increase the number of potential counterparties.	No update currently
▪ Complete Copper Mountain Solar 3 Purchase Option Evaluation	In early January 2024, Burbank Water and Power and LADWP stated they do not wish to proceed with the current purchase option for Copper Mountain Solar 3, but wish to continue the effort to be prepared to exercise the additional purchase option(s) in future years.
▪ Loyalton bankruptcy	The ARP Loyalton Settlement Agreement was approved by the SCPPA Board of Directors on December 21, 2023. Each of the ARP Loyalton Buyers has approved and executed the Settlement Agreement. The Bankruptcy Trustee is seeking bankruptcy court approval of the Settlement Agreement.

▪ Whitegrass/Star Peak PPA Issues Resolution	SCPPA staff is working with the participating Member, Glendale, and the PPA counterparties to finalize resolution of disputes related to the PPAs.
▪ Terminate SCPPA's participation in the Lower Colorado River Multi-Species Conservation Program (LCR MSCP)	SCPPA staff has drafted a letter to assign SCPPA's rights and obligations as Permittee and State Participant Group Member to the participating SCPPA Members. SCPPA staff will be meeting with affected Members to discuss the next steps and anticipates presenting on this matter to the SCPPA Board in May 2024.
▪ Magnolia & Tieton Audits	Amendment Number 2 to the Professional Services Agreement with Moss Adams and an additional Statement of Work for project related audit services was approved by the SCPPA Board on December 21, 2023. Moss Adams is expected to begin audit field work at the City of Burbank during week of 4/15/2024
▪ Linden balance of plant operating agreement	The Linden Wind Balance of Plant Operating Agreement was approved by the SCPPA Board on July 20, 2023 and has been executed.
▪ Pacific Northwest wind energy exchange agreements	he Pebble Springs Energy Exchange Agreement between PowerEx and SCPPA was approved by the SCPPA Board of Directors on November 16, 2023. The Linden Wind and Windy Flats/Wind Point Energy Exchange Agreements between PowerEx and SCPPA were approved by the SCPPA Board of Directors on December 21, 2023. All of the Wind Energy Exchange Agreements have been executed
▪ Casa Diablo IV REC dispute	Ormat has resolved all interconnection issues with Casa Diablo IV and has provided SCPPA with all previously outstanding RECs to date.
▪ Palo Verde Participation Agreement Amendment	APS has provided SCPPA and the other Palo Verde Owners with a list of proposed amendments to the Palo Verde Participation Agreement and is currently drafting an Amended and Restated Agreement for the Owner's consideration. APS's drafting of the proposed amended Palo Verde Participation Agreement is delayed due to higher priority work. SCPPA is continuing to check in with APS for updates.
▪ Chiquita Canyon Force Majeure	SCPPA received a Notice of Force Majeure from Ameresco regarding Chiquita Canyon on February 22, 2024 stating that they were forced to shut down the plan on January 31, 2024 due to a subsurface chemical reaction in the landfill and have not determined an expected date of return.
Provide transparency into operating project budgets, costs, and project risks: ▪ Project budget to actual variances	SCPPA Asset Management provides Quarterly Budget to Actual Variance reports to both Finance Committee and the SCPPA Board of Directors.
▪ Minimum energy requirements	SCPPA Asset Management provides Annual Guaranteed Energy Production Reports for select solar projects.

▪ RPS Certification	SCPPA Asset Management routinely verifies the CEC RPS Certification of existing project and reviews PPA requirements to ensure REC withholding provision are correctly followed.
▪ Certificates of Insurance	SCPPA Asset Management has compiled all SCPPA Project Certificates of Insurance on Laserfiche for review and to ensure compliance with PPA requirements.
▪ Performance Security	SCPPA Asset Management meets regularly to review the Performance Security provided by project developers and works with SCPPA Finance and SCPPA Legal to ensure receipt and accuracy of all Performance Security Documents.
OBJECTIVE: Control A&G Expenditures and Future Liabilities	
Evaluate cost effective options for Health Reimbursement Arrangements (HRAs) plans.	SCPPA had engaged a consulting firm to provide an analysis on projected future SCPPA cashflow if an HRA plan is implemented and the impact of the plan to SCPPA's future Other Post-Employment Benefits (OPEB) liability. The analysis shows that while there is current cashflow impact due to the funding of an HRA plan, the reduction in future OPEB liability far exceeds the cashflow impact. An HRA plan can be a cost-effective option in reducing OPEB liability. The results of the analysis were presented to the Executive Working Group. The next step of the evaluation is to engage with a firm with HRA expertise to further develop the details of the HRA plan and to present the plan to the SCPPA Board for consideration at a future meeting.
OBJECTIVE: Finance Projects	
Energy Prepay Financing	The work on the documents to finance an energy prepay is currently underway, with Anaheim as the project participant.
Linden Wind Energy Project Bond Refinancing	The Linden Wind Energy Project refunding revenue bonds were issued as variable rate demand bonds and were successfully priced on January 16, 2024, with an initial interest rate of 0.60%. The transaction closed on January 19, 2024.
Wind Point/Windy Flats Project Bond Refinancing	The Windy Point/Windy Flats Project refunding revenue bonds were successfully priced on October 31, 2023. The transaction closed on November 14, 2023. The refunding resulted in a net present value savings of $11.7 million.
Apex Power Project Bond Refinancing	SCPPA plans to refund the Apex Power Project, Revenue Bonds, 2014 Series A and B for debt service savings. The Authorizing Resolution to authorize the issuance of refunding revenue bonds is on the April 18, 2024 meeting agenda for the SCPPA Board consideration and approval. If approved, bond pricing is anticipated to be in May 2024, with the transaction closing in early June 2024.
Southern Transmission System (STS) Renewal Project - Second Tranche of Bond Financing	SCPPA plans to issue the second tranche of bonds to provide for the financing of the STS Renewal Project. The Authorizing Resolution to authorize the issuance of project revenue bonds is on the April 18, 2024 meeting agenda for the SCPPA Board consideration and approval. If approved, bond pricing is anticipated to be in the week of April 22, 2024, with the transaction closing in early May 2024.

COLLABORATION

Foster collaboration and professionalism for SCPPA and its Working Groups to maximize the value of SCPPA to its Members and the communities they serve.

Goals	Board Update
OBJECTIVE: Enhance Member and Employee Communications	
Evaluate a Member Working Group on Asset Management	First Asset Management Working Group Meeting scheduled on October 26th, 2023.
Annual joint Working Group meeting	SCPPA annual joint Working Group meeting was held on February 14, 2024 at the SCPPA Training Center with 90 attendees from SCPPA Member utilities.
Complete update to Employee Handbook	The SCPPA Employee Handbook has been updated to incorporate current laws. and was presented to SCPPA staff in March 2024, along with three new ancillary documents: an Injury and Illness Prevention Plan, a COVID-19 Prevention Plan, and a Family Medical Leave Act and California Family Rights Act Procedure.
Consider an ad hoc sub-working group to discuss NEM rate designs.	An Ad hoc sub-working group was established and has met twice. The meetings were well attended, and the discussions were meaningful and robust. The next meeting will be held during the first quarter of 2024.
Evaluate expanding the Public Benefits Working Group to include a focus on demand side management programs, as well as merge key accounts on an as-needed basis to promote customer adoption of programs.	The Demand Response/Reduction and Demand Working Group held its first meeting on Wednesday, March 27, 2024. Eighteen members attended
OBJECTIVE: Enhance SCPPA's business practices, transparency, and consistency with the Joint Powers Agreement	
Complete SCPPA Staff and Member Staff training on procurement and contract management procedures	SCPPA Staff has updated the Solicitation and Contract Management Procedure document to reflect the updated Procurement Code that was approved by the SCPPA Board in February 2023, as well as reflecting recommendations provided by Duncan, Weinberg, Genzer & Pembroke from their review of SCPPA's procurement processes. All SCPPA Staff have been provided with training on the updated solicitation and contract management procedures. A virtual training on the updated procedures was provided to Member Staff on April 2, 2024 and was recorded for future reference by Member Staff.
Update Project Procurement Procedures to match the 2023 approved SCPPA Procurement Codes.	Canyon: Amendments to the Canyon Special Procurement Rules were approved by the SCPPA Board in November 2023 and are currently in place. SCPPA Legal has reviewed specific procurement procedures for other projects and has determined that no updates are needed.
Assess areas where joint action distribution activities may be most beneficial to Members.	No update currently

Determine the Projects that have Board established Coordinating Committees that are Brown Act committees.	SCPPA Legal has prepared framework for SCPPA staff to evaluate, for each project, which committees must comply with the Brown Act and has worked with SCPPA staff to apply the framework to each current SCPPA committee. A list of SCPPA committees that are subject to the Brown Act has been prepared and finalized and saved to Laserfiche. The list was distributed to SCPPA Members on February 14, 2024 at the SCPPA Open House.
Implement State Compliant Records Storage System	Through our Laserfiche portal, we have contracted with Cities Digital, a software developer to implement a Records Management Module to secure, manage and store all SCPPA records though an automation process that is State Compliant and integrated with SCPPA's retention and disposal processes.
Evaluate whether, and to what extent to which building electrification and transportation electrification are consistent with the JPA.	SCPPA Legal has conducted legal research on this issue and anticipates finalizing a memo by May 2024.
OBJECTIVE: Support Member's Workforce Development to manage assets and programs	
Implement FY 2023-24 Training Program	**July 2023** • 07/12/2023 – 07/13/2023 | Transportation Electrification & Electric Vehicle Fundamentals | Completed. • 07/18/2023 | Traffic Control Technician and Flagger Operations Training | Completed. • 07/19/2023 | Traffic Control Technician and Flagger Operations Training | Completed. • 07/27/2023 | Maximizing Value of Energy Storage in CAISO Market (In-Person) | Completed. **August 2023** • 08-08-2023 - 08-10-2023| Technical Management Program (In-Person) | Completed. **September 2023** • 09/06/2023 – 09/07/2023 | Project Management Fundamentals (in-person) | Completed. **October 2023** • 10/05/2023 | Electric Utility Fundamentals + Insights (in-person) | Completed. • 10/16/2023 – 10/19/2023 | Project Management Professional (PMP) Exam Prep (In-Person) | In Progress • 10/24/2023 | Physical & Financial Gas Markets| In Progress **November 2023** • 11/07/2023 – 11/08/2023 | Understanding Demand Response (Virtual) | In Progress • 11/07/2023 – 11/09/2023 | Municipal Bond Fundamentals (In-Person) | In Progress • 11/14/2023 – 11/15/2023 | Applied Risk Management (Virtual) | In Progress • 11/27/2023 - 11/28/2023 | Gas Procurement, Scheduling, Power Plant Dispatch Decision Making for Municipalities | In Progress **December 2023** • 12/06/2023 – 12/07/2023 | Electric Utility Fundamentals + Insights (in-person) | Canceled **February 2024** • 2/05/2024 – 02/06/2024 | Project Management Fundamentals (in-person) | In Progress **March 2024**

	• 03/05/2024 through 03/06/2024| Scope and Requirements Management (In-Person) | Canceled • 03/12/2024 | Electric Utility Fundamentals + Insights (In-Person) | In Progress • 03/26/2024 I Cause Mapping Root Cause Analysis for Facilitators + Documentation Workshop (In-Person) Completed **April 2024** • 04/08/2024 -04/11/2024 | Project Management Professional PMP Exam Prep (In-Person) | register here • 04/16/2023 – 04/17/2023| PI System Collaboration, Discussion and Training by Aveva (in-person) | In Progress **June 2024** ▪ 06/13/2024 | Electric Utility Fundamentals + Insights (in-person) | In Progress
Internship Program Resolution	No update currently.
Work to develop granted funding for training within CMUA Workforce Development Grant	Marketing Materials are in progress
Determine feasibility of establishing SCPPA as Mandatory Continuing Legal Education provider and if feasible, develop a program to host utility-related legal training for SCPPA Member attorneys.	SCPPA Legal has determined that SCPPA can be a mandatory continuing legal education (MCLE) provider and has presented the results of its findings to the Legal Working Group. SCPPA Legal is working with SCPPA staff to coordinate a training in late April 2024 regarding the Inflation Reduction Act that will include MCLE credits for participating attorneys. SCPPA staff is also exploring the possibility of including MCLEs as part of SCPPA's annual conference in the fall.

EMERGING ISSUES

Help Members thrive and excel for the long term by exploring technological and operational solutions to emerging industry challenges and opportunities.

Goals	Board Update
OBJECTIVE: Develop Workshops for Member Discussion	
NEM 3.0	The NEM workshop was conducted in July 2023 and was attended by more than 70 members. The information shared by the two presenters was very informative and well received by the attendees.
Transmission Planning Member meeting	Reaching out to various Member and BA transmission planners to have a joint discussion either in-person or virtually in Q2 of 2024.
Annual Meeting	The 2024 Annual Conference is scheduled for October 10, 2024 at the Grand Sheraton In Los Angeles.
Transmission and Distribution Annual Meeting	T&D E&O Conference is scheduled for November 6, 2024. Place and Time to be determined.
Develop and conduct 2 or more emerging issue mini-workshops/seminars next year	Planning to arrange and conduct two mini-workshops by end of June 2024.

▪ Advanced Distribution Management Systems	
Inflation Reduction Act Implementation and IRA financial tool demonstration	IRA financial tool currently under Beta testing. Hope to roll out model by end of January 2024 to all interested Members for use and further development.
Support Member IRP Development	Beginning February 2024, each Member that has an approved IRP by their city will present their IRP during the monthly Resource Planning Working Group Meetings (one per month).

OBJECTIVE: Support IRP Development

DECARBONIZATION

Champion decarbonization efforts for Member communities through collective projects, programs, and services to meet sustainability goals while maintaining reliability, low costs, and local control.

Goals	Board Update
OBJECTIVE: Develop Renewable, Storage, and zero-carbon Projects	
Wind	All wind proposals submitted to the 2023 Renewables RFP have been presented to all Members and are currently under evaluation by interested Members. The 2024 Renewables RFP was posted on February 1, 2024, on the SCPPA website and was sent to vendors on the SCPPA RFP Distribution List.
Solar	SCPPA and participating Members are in negotiations with a number of solar-only and solar plus energy storage projects within and outside of the CAISO. The Daggett 2 Solar and Energy Storage Project achieved Commercial Operation on December 12, 2023. This is the first SCPPA solar plus storage project to reach COD. The 2024 Renewables RFP was posted on February 1, 2024, on the SCPPA website and was sent to vendors on the SCPPA RFP Distribution List.
Geothermal	No update currently
Standalone Storage	SCPPA and participating Members are in negotiations with a developer for a standalone storage project agreement within the CAISO. Other proposals submitted to the 2023 Standalone Storage RFP are currently under evaluation by interested Members. The 2024 Standalone Storage RFP was posted on March 29, 2024 on the SCPPA website and was sent to vendors on the SCPPA RFP Distribution List.
Resource Adequacy	SCPPA and participating Members are in negotiations with a developer for a resource adequacy (RA) only agreement within the CAISO. Other proposals submitted to the 2023 Standalone Storage RFP are currently under evaluation by interested Members. The 2024 Standalone Storage RFP (including RA Only) was posted on March 29, 2024 on the SCPPA website and was sent to vendors on the SCPPA RFP Distribution List.
Carbon Free Power Project	On November 8, 2023, UAMPS and NuScale Power mutually agreed to terminate the Carbon Free Power Project due to a lack of project subscriptions to further deployment.
Power from the Prairie (PftP)	SCPPA and a participating Member will be part of the 4000 MW transmission line PftP Stage 2 Proof of Concept Study. A study project has been created at SCPPA for PftP. However, on March 19, 2024, the sole project participant, Burbank, notified SCPPA that it is no longer interested in pursuing the project. PftP has been notified.

OBJECTIVE: Promote Joint Action to the greatest extent possible and help Members to move towards compromise to achieve the benefits.	
(To be determined)	No update currently
OBJECTIVE: Improve project procurement process and agreements to be competitive while managing risk	
Develop recommendations on procurement process improvements.	SCPPA has worked with the law firm Cameron Daniel to develop a draft pro forma PPA. The draft is under review by the Legal Working Group and will be finalized for use with SCPPA's summer RFP.
Renewable PPA	SCPPA has worked with the law firm Cameron Daniel to develop a draft pro forma PPA. The draft is under review by the Legal Working Group and will be finalized for use with SCPPA's summer RFP.
Standalone Storage PPA	SCPPA working with various outside legal firms and Member city attorneys to establish new pro forma Energy Service Agreements (ESAs) to be used in future 2024 RFPs.
Power Sales Agreements	Upon completion of the new PPA template, SCPPA Legal will make appropriate modifications to the Power Sales Agreement and will review the proposed modifications with the Legal Working Group and commercial teams for their input.
OBJECTIVE: Help Members decarbonize through Energy Efficiency and Demand Response Programs	
Energy Efficiency RFPs and contracts:	RFP and contract for electric meter data aggregation and analysis services. ▪ Contract has been finalized and the vendor is providing services to interested members. RFP for electronic energy efficiency newsletters. Award by Q4, 2023 ▪ SCPPA was unable to finalize the agreement with the selected proposer. During the course of the RFP process, the vendor was acquired by another company, and despite the SCPPA team's best efforts, an agreement could not be reached. Typically, SCPPA would enter into discussions with the 2nd place bidder, but unfortunately, there was no suitable runner-up. SCPPA staff will regroup, research the market to determine if there are additional companies that provide of this type of service, and if so, the SCPPA Team will issue a new RFP no later than Q3 2024. Energy Efficiency Contract Q1 2024 ▪ This action will be deferred to Q3 or Q4 2024 as several existing SCPPA contracts for Energy Efficiency had an additional 3-year term that was exercised. Consider advancing "Smart Charging" programing opportunities. ▪ An RFP for EVSE is being finalized and should be ready for release before the end of Q2.
Identify and encourage the development and implementation of Demand Response related "Electrification Transportation", and other electrification strategies that align with and are supported by SCPPA's PPA.	RFP/RFQ for public charger installation and maintenance services. Award(s) Q1, 2024 ▪ SCPPA Legal has drafted an RFP for the project. Programs Team and EV Working Group are workign on adding specifics into the RFP such as scope of work, minimum criteria, pricing forms. The RFP is planned to be issued by end of Q2 of 2024. Submit CFI grant as a group effort for 5 SCPPA Members to seek funding for public chargers. ▪ The Grant request was accepted. Notice of the CFI grant recipients was released in Q1 2024, and unfortunately, the joint SCPPA member project was not selected.

SCPPA FEBRUARY BOARD MEETING
PALO VERDE NUCLEAR GENERATING STATION
STATUS REPORT

Plant Operations - Following is the status of the plant as of March 15, 2024:

- Unit 1 is operating at full power and is in its 125th day of continuous operation.
- Unit 2 is operating at full power and is in its 285th day of continuous operation.
- Unit 3 is operating at full power and is on its 225th day of continuous operation.

Through February 2024, the year-to-date maximum dependable capacity factor of the station is as follows:

	Capacity Factor
Unit 1	100.0%
Unit 2	94.1%
Unit 3	98.7%
Station	97.6%

Budget:

Through February 2024, the year-to-date cost report is summarized as follows:

(In $millions)

Year-to-Date	Budget	Actual	Variance
O&M	102.47	102.04	(0.43)
Capital	29.95	31.65	1.70
Fuel	25.77	22.80	(2.97)
Total	158.18	156.49	(1.70)

The year-end budget projection is as follows:

Year-End	Budget	Forecast	Variance
O&M	724.00	724.00	0.00
Capital	258.00	258.00	0.00
Fuel	210.05	210.05	0.00
Total	1,192.05	1,192.05	0.00

Developments:

- **Unit 2 Downpower**

  Unit 2 commenced a downpower from 100% to 40% on February 14, 2024 for Condenser 1A Hotwell Tube leak repair, and returned to full power on February 17, 2024.

Sean Kigerl
(818) 238-3774
April 18, 2024

MAGNOLIA POWER PLANT
OPERATIONS REPORT
March 2024

Reporting Period

March 1-31, 2024

Workforce Safety Statistics

- There were zero (0) lost time accidents this month and zero (0) year-to-date (YTD).
- There were zero (0) reportable incidents in March and zero (0) YTD.

Plant Performance Information

- **Availability:** 82.1% in March, 96.1% fiscal year-to-date (FYTD), and 93.9% YTD. (A table showing monthly plant availability for the past fifteen months is attached.)
- **Unit Capacity Factor (240 MW):** 58.0% in March, 73.7% FYTD, and 75.3% YTD.
- **Fired Factored Hours:** 610.5 hours in March 2024.
- **Plant Starts (5 starts/month allowed):** One (1) start used during March.
- **Statistics:** Details are provided on the attached monthly production report entitled "Year-to-Date Summary of Statistics FY 2023-24 & CY 2024".

Plant Outage Summary and Other Actions Taken by Operating Agent

- MPP was shut down on March 15, 2024, to perform an offline water wash of the combustion turbine compressor, boiler inspection and balance of plant maintenance. MPP was restarted on March 21, 2024.
- A table entitled "Outage Summary" is attached it shows all the outages that have occurred over the past twelve (12) months. The "2024-2028 Scheduled Inspection Plan" is also attached showing the calendar for future planned outages at MPP.
- There were no instances of stranded energy in March 2024 (a table showing stranded energy by month is attached).

MAGNOLIA MONTHLY PRODUCTION REPORT
Year-to-Date Summary of Statistics
FY 2023-24 & CY 2024

		2023	2023	2023	2023	2023	2023	2024	2024	2024	2024	2024	2024		
		Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**FYTD**	**YTD**
ENERGY															
Combustion Turbine (Gross)	MWH	90,631	87,895	73,952	67,533	82,141	84,689	103,171	86,488	64,558				741,059	254,217
Steam Turbine	MWH	56,269	56,580	49,211	49,713	52,441	51,752	58,944	52,629	42,990				470,529	154,563
Plant Generation (Gross)	MWH	146,900	144,475	123,163	117,246	134,583	136,441	162,115	139,116	107,548				1,211,588	408,779
Plant Auxiliaries (Unit Aux.)	MWH	5,328	5,293	4,611	5,051	5,092	4,826	5,286	4,779	3,945				44,211	14,010
Plant Auxiliaries (Reserve)	MWH	6	7	359	7	6	330	7	6	583				1,311	596
Plant Generation (Net)	MWH	141,573	139,182	118,552	112,195	129,490	131,615	156,829	134,337	103,603				1,167,378	394,769
Capacity Factor (240 MW Net)	%	79.3%	77.9%	68.6%	62.8%	74.9%	73.7%	87.8%	80.4%	58.0%				73.7%	75.3%
THERMAL EFFICIENCY															
Combustion Turbine (Gross)	BTU/KWh	11,966	12,051	12,376	13,519	12,229	11,797	11,348	11,874	12,628				12,129	11,852
Total Plant (Gross)	BTU/KWh	7,412	7,431	7,531	7,792	7,464	7,350	7,228	7,384	7,583				7,449	7,374
Total Plant (Net)	BTU/KWh	7,691	7,714	7,824	8,143	7,758	7,619	7,472	7,646	7,871				7,731	7,636
AVAILABILITY															
Hours in the Month	Hours	744.0	744.0	720.0	744.0	720.0	744.0	744.0	696.0	744.0				6,600.0	2184.0
Plant Operating Hours	Hours	744.0	744.0	659.5	744.0	720.0	683.5	744.0	696.0	610.5				6,345.5	2050.5
Duct Burner Operating Hours	Hours	33.6	95.3	60.5	4.9	0.1	12.7	8.6	4.0	4.0				223.5	16.5
Plant Availability	%	100.0%	100.0%	91.6%	100.0%	100.0%	91.9%	100.0%	100.0%	82.1%				96.1%	93.9%
Offline yet Available Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				0.0	0.0
Planned Outage Hours	Hours	0.0	0.0	60.5	0.0	0.0	60.5	0.0	0.0	132.5				253.5	132.5
Forced Outage Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				0.0	0.0
Forced Outage	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%				0.0%	0.0%
Total Hours Offline	Hours	0.0	0.0	60.5	0.0	0.0	60.5	0.0	0.0	132.5				253.5	132.5
Forced Derated Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				0.0	0.0
(FFH) From Peak Power	Hours	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				0.0	0.0
Total Factored Fired Hours	Hours	744.0	744.0	659.5	744.0	720.0	683.5	744.0	696.0	610.5				6,345.5	2,050.5
(FFH) Before Next Inspection	Hours	12,684	11,940	11,281	10,537	9,817	9,133	8,389	7,693	7,083				-	-
Estimated Date of Next Major Outage														Jan 2025	
FUEL USAGE AND QUALITY															
Combustion Turbine	DTH	1,084,506	1,059,216	915,235	912,961	1,004,543	999,045	1,170,829	1,026,952	815,267				8,988,555	3,013,048
Duct Burner	DTH	4,312	14,388	12,349	605	4	3,783	1,012	227	227				36,907	1,466
Duct Burner	MMSCF	4.1	13.7	11.8	0.6	0.0	3.6	1.0	0.2	0.2				35	1
Duct Burner Fuel Remaining	MMSCF	550.3	536.6	524.8	524.2	524.2	520.6	519.7	519.4	519.2				-	-
Total Plant Usage	DTH	1,088,819	1,073,604	927,585	913,566	1,004,547	1,002,827	1,171,841	1,027,179	815,494				9,025,462	3,014,514
Gas BTU (HHV)	BTU/SCF	1,039	1,032	1,034	1,033	1,030	1,031	1,039	1,039	1,050				1,036	1,043

Magnolia Power Plant - Outage Summary

Outages During the Reporting Period March 1-31, 2024				
Outage Type	**Start Date/Time**	**End Date/Time**	**Hours**	**Comments**
PO	3/15/24 6:04 PM	3/21/24 6:34 AM	132.5	Boiler Inspection/CT water wash

Summary of Outages During the Past Twelve Months				
Outage Type	**Start Date**	**End Date**	**Hours**	**Cause**
PO	June 23, 2023	June 26, 2023	60.5	CT water wash
PO	September 22, 2023	September 25, 2023	60.5	CT water wash
PO	December 15, 2023	December 18, 2023	60.5	CT water wash

Outage Type Legend
RS - Reserve Shutdown
PO - Planned Outage
FO - Forced Outage
OMC - Outside of Management Control

Magnolia Power Plant - Availability Summary Table

<table>
<tr><th>Monthly</th><th>Quarterly</th><th>Semi-Annually</th><th>Annually</th></tr>
<tr><td>Jan-23
99.1%</td><td rowspan="3">Q1 '23
93.5%</td><td rowspan="6">H1 '23
95.4%</td><td rowspan="12">Yr '23
96.3%</td></tr>
<tr><td>Feb-23
100.0%</td></tr>
<tr><td>Mar-23
82.1%</td></tr>
<tr><td>Apr-23
100.0%</td><td rowspan="3">Q2 '23
97.2%</td></tr>
<tr><td>May-23
100.0%</td></tr>
<tr><td>Jun-23
91.6%</td></tr>
<tr><td>Jul-23
100.0%</td><td rowspan="3">Q3 '23
97.3%</td><td rowspan="6">H2 '23
97.3%</td></tr>
<tr><td>Aug-23
100.0%</td></tr>
<tr><td>Sep-23
91.6%</td></tr>
<tr><td>Oct-23
100.0%</td><td rowspan="3">Q4 '23
97.3%</td></tr>
<tr><td>Nov-23
100.0%</td></tr>
<tr><td>Dec-23
91.9%</td></tr>
<tr><td>Jan-24
100.0%</td><td rowspan="3">Q1 '24
93.9%</td><td></td><td></td></tr>
<tr><td>Feb-24
100.0%</td><td></td><td></td></tr>
<tr><td>Mar-24
82.1%</td><td></td><td></td></tr>
</table>

Magnolia Power Project

2024-2028

Scheduled Inspection Plan with 32K Hardware

Offline Water Wash (green)
Hot Gas Path / Minor Inspection (red)
Major Inspection (blue)

As of April 5th, 2024

Total Fired Time	137,260.0 Hours

Total Fired Hours PROJECTED ANNUALLY	2024 (8,472 Hours)	2025 (7,380 Hours)	2026 (8,448 Hours)	2027 (8,448 Hours)	2028 (8,472 Hours)
INSPECTIONS **Water Wash** 90 Day Intervals Every 2,160 Hours	69 136,897 Hrs. March 2024 **Offline 6:00 PM 3/15/2024** **Online 6:00 AM 3/21/2024** **CT Borescope/Boiler Inspection**	73 3 February 2025 **Offline 6:00 PM 2/28/2025** **Online 6:00 AM 4/21/2025** **Minor Inspection/Rotor Rep./Boiler Inspection**	76 January 2026 **Offline 6:00 PM 1/23/2026** **Online 6:00 AM 1/29/2026** **CT Borescope/Boiler Inspection**	80 February 2027 **Offline 6:00 PM 2/5/2027** **Online 6:00 AM 2/11/2027** **CT Borescope/Boiler Inspection**	84 February 2028 **Offline 6:00 PM 2/4/2028** **Online 6:00 AM 2/10/2028** **CT Borescope/Boiler Inspection**
Hot Gas Path / Minor Inspection Every 32,000 Hours Last HGP @ 81,095 Hrs	70 June 2024 **Offline 6:00 PM 6/21/2024** **Online 6:00 AM 6/24/2024**	74 July 2025 **Offline 6:00 PM 7/18/2025** **Online 6:00 AM 7/21/2025**	77 May 2026 **Offline 6:00 PM 5/1/2026** **Online 6:00 AM 5/04/2026**	81 May 2027 **Offline 6:00 PM 5/7/2027** **Online 6:00 AM 5/10/2027**	85 May 2028 **Offline 6:00 PM 5/5/2028** **Online 6:00 AM 5/8/2028**
Major Inspection Every 64,000 Hours Last Major @ 112,229 Hrs	71 September 2024 **Offline 6:00 PM 9/20/2024** **Online 6:00 AM 9/23/2024**	75 October 2025 **Offline 6:00 PM 10/17/2025** **Online 6:00 AM 10/20/2025**	78 July 2026 **Offline 6:00 PM 07/31/2026** **Online 6:00 AM 08/03/2026**	82 August 2027 **Offline 6:00 PM 8/6/2027** **Online 6:00 AM 8/9/2027**	86 August 2028 **Offline 6:00 PM 8/4/2028** **Online 6:00 AM 8/7/2028**
Upcoming Inspections Minor Inspection CT Rotor Replacement **02/28/2025-04/21/2025** All future dates are estimates based on run hours and are subject to change.	72 December 2024 **Offline 6:00 PM 12/13/2024** **Online 6:00 AM 12/16/2024**		79 November 2026 **Offline 6:00 PM 11/06/2026** **Online 6:00 AM 11/09/2026**	83 November 2027 **Offline 6:00 PM 11/5/2027** **Online 6:00 AM 11/8/2027**	87 November 2028 **Offline 6:00 PM 11/3/2028** **Online 6:00 AM 11/6/2028**
End Of Year Totals	143,576 Hours	150,956 Hours	159,404 Hours	167,852 Hours	176,324 Hours

Stranded Energy Monthly Report

Month	Participant	Energy (MWh)
Jan-23	-	-
Feb-23	-	-
Mar-23	-	-
Apr-23	-	-
May-23	-	-
Jun-23	-	-
Jul-23	-	-
Aug-23	Cerritos	2
Sep-23	-	-
Oct-23	Cerritos	19
Nov-23	-	-
Dec-23	-	-
Jan-24	-	-
Feb-24	-	-
Mar-24	-	-

Memo

TO: Southern California Public Power Authority
FROM: TFG
RE: Federal Legislative Report
DATE: April 10, 2024

March 2024 Federal Report

This legislative report covers activities related to appropriations, energy, and environment, as well as telecommunication and cybersecurity issues from February 1 through March 1, 2024

Executive Summary

Congressional Calendar. The House and Senate were in session for two weeks in March, taking an extended break for the Easter Recess.

FY 24 Budget and Appropriations. Work on the the FY2024 Appropriations bills has been completed and all been signed in to law. Also, on March 11th, President Biden will submit his FY 2025 budget request to Congress, kicking off the FY 2025 budget process in Congress.

Energy and Environment. Among other activities, EPA is seeking comment on the scope and nature of a new rule on regulating existing natural gas plants, Diablo Canyon's continued operations comes under scrutiny, and Treasury continues work on clean energy renewable energy credit regulations.

Cybersecurity and Telecommunications. Among other cybersecurity activities, a presidential advisory board adopted a report recommending that the Biden administration consider offering tax breaks, grants, or other financial incentives to encourage private-sector entities to adopt better cybersecurity practices. Regarding telecommunications developments, the National Telecommunications and Information Administration (NTIA) released a national spectrum strategy implementation plan that calls for the October 2026 release of reports on the two most-watched spectrum bands. The plan established a road map, including deadlines for action, on studies of all five bands. Deadlines for public release of reports are between November of this year and October 2026

Budget and Appropriations

FY 2024 Appropriations Cycle

-

The House passed the second FY24 minibus package on March 22 by a vote of 286-134, followed by the Senate on March 23 by a vote of 74-24. President Biden signed the second minibus package into law (P.L. 118-47) on the afternoon of March 23. The package includes $1.89 billion for 1,469 earmarks (known formally as "Community Project Funding" requests in the House and "Congressionally Directed Spending" requests in the Senate). A TFG special report with a summary of the second FY24 minibus package is available here.

Congressional leaders released the final bill text for a $436 billion FY 2024 "minibus" appropriations package, the "**Consolidated Appropriations Act, 2024**" (H.R. 4366), consisting of the following six FY24 spending bills:

- **Agriculture – Rural Development – Food and Drug Administration**
- **Energy – Water Development**
- **Military Construction – Veterans Affairs**
- **Transportation – Housing and Urban Development**
- **Commerce – Justice – Science**
- **Interior—Environment**

The House passed the FY24 minibus package on March 6 by a vote of 339-85, followed by the Senate on March 8 by a vote of 75-22. President Biden signed the minibus package (P.L. 118-42) into law on the morning of March 9. The package includes $12.7 billion for 6,628 earmarks (known formally as "Community Project Funding" requests in the House and "Congressionally Directed Spending" requests in the Senate). A TFG special report with a summary of the first FY24 minibus package is available here.

On March 21, Congressional leaders released the final bill text for a $1.2 trillion FY 2024 minibus appropriations package, the "**Further Consolidated Appropriations Act, 2024**" (H.R. 2882), consisting of the remaining six FY24 spending bills:

- **Defense**
- **Financial Services—General Government**
- **Homeland Security**
- **Labor—Health and Human Services—Education**
- **Legislative Branch**
- **State—Foreign Operations**Energy and Environment

Energy and Environment

EPA Considering Nat. Gas Powerplants Regulation

EPA has begun to take public comment on whether they should regulate carbon dioxide from natural gas-fired power plants.

The establishment of agency's "non-regulatory docket" is likely first step for the agency to write a new climate rule for the existing gas fleet.

The comment period closes May 28, 2024.

Among others, EPA is asking for comments on the kinds of carbon control technology that should be the new rule's "best system of emissions reduction."

Other questions being posted are whether the agency should allow trading between emission sources under the new rule and, if so, whether it should include safeguards to ensure trading doesn't subject neighboring communities to added air pollution.

Previously, states and utilities have generally supported trading and averaging provisions as a way to reduce regulatory costs.

However, communities near the plants have generally argued that those programs allow cleaner facilities in one region to make up for subpar ones that are frequently near minority and poor populations.

This action comes shortly after EPA announced that it wouldn't move forward with last year's proposed rule for existing gas plants -- which was controversial with both utilities and environmental justice groups. The agency said it would instead offer a new climate proposal soon and initiate separate rules for local air pollutants and toxic emissions from gas-fired generation. This is a first step in response to that.

This latest action related to the non-regulatory docket effectively pushes regulation of existing gas plants back more than a year. The previous standard was due to be finalized next month — while EPA is still planning to finalize rules for new gas and existing coal-fired power plants. Environmentalists say they hope the replacement rule will be final by the end of 2025, which assumes President Joe Biden wins reelection in November.

California Takes Action in Court Over Company Climate Disclosures

The state of California has filed a motion asserting its authority to compel climate-related disclosures from large companies operating in the state through California bills S.B. 253 and S.B. 261, arguing that the U.S. Chamber, California Chamber of Commerce, American Farm Bureau Federation and other groups in the federal lawsuit haven't yet suffered and that the federal Clean Air Act doesn't preemptively bar the state from implementing its laws.

In a 34 page filing, the state responds to the business groups' assertion that California is seeking to "regulate greenhouse-gas emissions outside of [California's] own borders" — not from actual regulation of the emissions themselves, since the laws only require disclosure, but from "pressure."

"On Plaintiffs' theory, any 'pressure' companies feel would come from third parties — investors, customers, and the like — not from the State itself," California's attorneys wrote. "And courts routinely distinguish between pressure created by state laws and actual regulation by the State, and recognize only the latter as an actionable injury."

The state also argues that because the California Air Resources Board hasn't yet adopted rules requiring the disclosures, claims of financial burden, "risk" and "stigma" are premature. CARB is required to finalize those rules by Jan. 1, 2025.

Gov. Gavin Newsom (D) signed S.B. 253 and S.B. 261 last year after a bruising fight in the Legislature, particularly over S.B. 253, which requires large companies to disclose their full carbon footprint, including Scope 3 emissions stemming from their supply chains. S.B. 261 requires businesses to disclose their climate-related financial risks.

CalChamber lobbied hard against S.B. 253, contending that the Scope 3 reporting requirements would incur burdensome costs on businesses and that the resulting data would be unreliable.

The state also highlights in its filing that the original lawsuit from business groups does not allege harm from the mandated disclosure of more direct emissions under scopes 1 and 2 — and that it is "reasonable to conclude that the final regulations may be responsive" to the Scope 3 concerns.

The laws go further than recently finalized federal climate disclosure rules, which the Chamber is also suing over, in that they apply to both publicly traded and privately held companies and because of the Scope 3 disclosure requirement.

Newsom referenced concerns over both the implementation timeline and cost of compliance in his signing statement. And CalChamber said it would continue to pursue "clean up" legislation this year.

U.S. District Court Judge Fernando Olguin is set to consider the case on June 20. The business groups have until May 1 to file an opposition to the motion to dismiss.

Diablo Canyon Licensing Update

There have been two recent developments in Pacific Gas &Electric's (PG&E) efforts to extent the state's only nuclear plant's operating life.

First, the California Coastal Commission is investigating whether PG&E cleared debris from plant's water intake structure without a permit and second, two environmental groups -- Mothers for Peace, Environmental Working Group and Friends of the Earth -- have filed an objection to PG&E's application to the Nuclear Regulatory Commission (NRC) to extend the plant's life, arguing that a recent earthquake in Japan raises new concerns about the potential for a serous earthquake near the plant.

PG&E is taking steps to keep the plant open until 2030, five years longer than expected, following a decision by state lawmakers two years ago that California needed the plant to keep the lights on as it transitions to a state wide decarbonization. The application the NRC is considering would authorize the plant going for up to 20 more years – a standard license extension petition.

Diablo, which started operations in 1985, circulates 2.5 billion gallons of seawater each day to cool its reactors. It was slated to close its twin reactors in 2024 and 2025, but Gov. Gavin Newsom and lawmakers reached agreement in 2022 to extend its operations (the plant supplies approximately eight percent of the state's electrical power).

The Coastal Commission started its investigation in response to PG&E's request to dredge sediment from around the plant's water intake pipes, a proposal it first made in 2023. The agency said divers are already using water hoses to clear sediment and debris from the intake structure without a coastal development permit, which may or may not be allowed.

Regarding the concerns about the risk form an earthquake, PG&E has performed a new review of seismic risk as ordered in state Senate Bill 846, which authorized the plant's extension. The analysis, which is expected to become public in a few weeks, has reportedly found no significant increase in seismic risk.

PG&E is aware of the Japanese quake and the successful performance of a nearby nuclear plant and is planning follow-up work to understand any implications for the faults near Diablo.

The NRC review is likely to take nearly two years from when PG&E's application was accepted in December 2023. The agency authorized PG&E to keep the plant going while it performs its review

Treasury Advancing Clean Energy Tax Credit Rules

Treasury continues to take on rulemakings related to the direct pay credits. Most recently, a final rule has been issued which is primarily focused on the process and timeline for claiming and receiving an elective payment of energy tax credits.

Importantly, however, it does not provide guidance for meeting domestic content requirements for claiming the payment, nor does it discuss the exceptions to those requirements.

While Treasury issued draft proposed rules for the domestic content bonus credit in 2023, it has yet to clarify whether this bonus credit domestic content requirements would also apply for purposes of qualifying for elective payment. Likewise, while Treasury and IRS have sought comments on exceptions to the domestic content requirements for elective payment, they have not issued any guidance – draft or otherwise.

A positive development: the final rule addresses the problem faced by POUs operating on a fiscal year, but that placed energy property – including commercial electric vehicles – into service early in calendar year 2023. Because of the mechanics of elective payment's effective date, such entities were at risk of being unable to claim credit for such property. Under the final rule, an entity that had not previously filed an income tax return, may choose whether to file its first Form 990-T based upon either a calendar or a fiscal year. This should allow affected POUs that placed in service applicable energy credit property early in 2023 to file Form 990-T based on a calendar year and make an elective payment election with respect to the applicable credit property.

This latest action is part of the Biden administration's continued efforts to make an aggressive push to finalize rules governing how clean energy tax credits can be monetized under the Inflation Reduction Act. The Treasury Department is also expected to begin the process of setting the rules for broad, technology-neutral credits that will take effect in 2025 (e.g. Law calls for PTC and ITC to transition to technology neutral by 2026).

Treasury is also planning to provide further guidance on other tax credits in the coming months, including for the alternative fuel vehicle refueling credit designed assist in catalyze the development of a network of electric vehicle chargers as well as make initial awards and issue a notice establishing the second round of allocations for the advanced energy project tax credit. The credit is aimed at expanding clean energy into traditionally coal-reliant communities. Treasury also intends to announce information on this year's program under the low income communities bonus tax credit prior to the opening of the second year of applications.

In addition, Treasury also recently issued a Notice of Proposed Rulemaking (NPRM) providing additional clarity for owners seeking elective payment for their portion of co-owned energy projects.

Finally, there is no specific timeline for finalizing guidance on the clean hydrogen tax credit., which did not address uncertainties surrounding questions on whether there will be pathways for existing, legacy sources like nuclear and open questions surrounding the use of renewable natural gas.

Telecommunications and Cybersecurity

Telecommunications

National Spectrum Strategy: The National Telecommunications and Information Administration (NTIA) released a national spectrum strategy implementation plan that calls for the October 2026 release of reports on the two most-watched spectrum bands. The plan established a road map, including deadlines for action, on studies of all five bands. Deadlines for public release of reports are between November of this year and October 2026. The latter ate is for the 3.1-3.45 gigahertz and 7/8 GHz bands (7125-8400 megahertz). The plan also sets a timeline for action, including deadlines, for other steps called for in the strategy, including establishing a strategic spectrum management process, facilitating investments in new and emerging spectrum technologies, and expanding spectrum expertise and elevating national awareness on spectrum.

Senate Commerce Spectrum Hearing: The Senate Commerce, Science, and Transportation Committee held a full committee hearing on March 21 on the link between spectrum and national security. The hearing focused on how a coordinated and comprehensive approach to domestic spectrum policy is critical to U.S. national security. The hearing focused on the FCC's spectrum auction authority, engagement in fact-based spectrum decision-making, and investments in dynamic spectrum sharing technologies. Witnesses included Clete Johnson, senior fellow in the Center for Strategic and International Studies' Strategic Technologies Program; Open RAN Policy Coalition Executive Director Diane Rinaldo; Monisha Ghosh, an engineering professor at the University of Notre Dame; Mary Brown, who will be testifying as executive director of WifiForward; and Harold Furchtgott-Roth, senior fellow and director of the Hudson Institute's Center for the Economics of the Internet.

FCC Broadband Speed Definition: Over the dissents of the Federal Communications Commission's two Republican members, the FCC increased its broadband speed benchmark for the purposes of determining whether advanced telecommunications capability is being deployed in a reasonable and timely fashion across the U.S. from 25 megabits per second downstream and 3 Mbps upstream to 100 Mbps/20 Mbps, with a long-term goal of 1 gigabit per second downstream and 500 Mbps upstream. The Section 706 report adopted at the Commission's March 14 Open Meeting, FCC meeting found that advanced telecommunications capability is not being deployed in a reasonable and timely fashion. The Section 706 report is named for the provision of the 1996 Telecommunications Act that mandates the annual report.

6 GHz FNPRM: The FCC mainly received support, along with numerous suggested modifications, in recent filings to the Commission for a second further notice of proposed rulemaking (FNPRM) on whether it should expand use of very low power (VLP) devices to an additional 350 megahertz of the 6 gigahertz band and permit Very Low Power (VLP) devices to use higher power levels while employing a geofencing system to protect licensed incumbent operations. Last October, the FCC unanimously adopted the second FNPRM in ET docket 18-295 and GN docket 17-183 at the same time it approved a second report and order authorizing VLP operations in the U-NII-5 and U-NII-7 portions of the 6 GHz band totaling 850 megahertz of spectrum. Last October's item followed up on a 2020 6 GHz band order that saw the FCC authorize low-power indoor (LPI) operations over the entire 1,200 MHz of spectrum; standard-power devices were permitted in 850 MHz of the band subject to the operation of automated frequency coordination (AFC) systems. A further notice of proposed rulemaking solicited comment on permitting VLP devices to operate indoors and outdoors and increasing the power levels for low-power indoor (LPI) devices.

NTIA Permitting Application: The NTIA unveiled a mapping tool, the NTIA Permitting and Environmental Information Application, aimed at helping "grant recipients and others deploying infrastructure identify permit requirements and avoid potential environmental impacts when connecting a particular location to high-speed Internet service." The application is designed to help federal broadband grant recipients and subgrantees identify and understand the types of permits they will need and plan routes for their broadband deployments, according to an NTIA announcement. The application can be found here.

Cybersecurity

CISA Reporting Obligations: The Cybersecurity and Infrastructure Security Agency (CISA) published proposed cyber incident reporting obligations for critical infrastructure entities that are deliberately wide-ranging in their definitions of "covered entity" and incidents that need to be reported. "CISA believes a broad interpretation of the term covered entity is essential," it said in a notice of proposed rulemaking (NPRM) that's due to be published in the Federal Register on April 4. The NPRM would implement the provisions of the Cyber Incident Reporting for Critical Infrastructure Act (CIRCIA), a landmark 2022 statute that requires critical infrastructure entities to report significant cyber incidents to CISA within 72 hours and ransomware payments within 24 hours.

NSTAC Cybersecurity Incentives: A presidential advisory board adopted a report recommending that the Biden administration consider offering tax breaks, grants, or other financial incentives to encourage private-sector entities to adopt better cybersecurity practices. The President's National Security Telecommunications Advisory Committee (NSTAC) unanimously adopted the report, titled "Measuring and Incentivizing the Adoption of Cybersecurity Best Practices." The report found that financial incentives provided by the government could persuade private-sector entities to boost their spending on cybersecurity beyond what companies believe is appropriate for their own business needs. One of the recommendations addressed the harmonization of cybersecurity regulatory requirements for private-sector entities, a topic that is receiving increased attention as various federal agencies implement separate rules for specific business sectors.

AGENDA ITEM STAFF REPORT

MEETING DATE:	April 18, 2024	**RESOLUTION NUMBER:**	2024-012

SUBJECT: Adoption of a Resolution Correcting an Error in Resolution No. 2024-001 regarding SCPPA's Employee Benefits Policy

DISCUSSION: ☒ **OR** **CONSENT:** ☐

Select the appropriate box(es):

FROM:		**METHOD OF SELECTION:**	
Finance	☐	Competitive	☐
Project Development	☐	Cooperative Purchase	☐
Program Development	☐	Sole Source	☐
Regulatory/Legislative	☐	Single Source	☐
Project Administration	☐	Other *(Please describe)*:	
Legal	☒	N/A	
Executive Director	☐		

MEMBER PARTICIPATION:

Sponsoring Members: N/A

Other Members Potentially Participating: N/A

Approved by Acting/Interim Executive Director: DocuSigned by: Randolph R. Krager 40619458107B4D2...

RECOMMENDATION:
It is recommended that the Board adopt a resolution to correct an error in the exhibit to Resolution No. 2024-001. Resolution 2024-001, adopted by the Board of Directors (Board) on January 18, 2024, amended SCPPA"s Employment Benefits Policy to add Juneteenth as a paid SCPPA Holiday.

BACKGROUND AND DISCUSSION:

On January 18, 2024, the SCPPA Board of Directors adopted Resolution 2024-001, which amended SCPPA's Employee Benefits Policy to add Juneteenth as a paid SCPPA holiday. A revised Employee Benefits Policy (adding Juneteenth) was attached to Resolution 2024-001 as Exhibit 1.

Unfortunately, the version of the Employee Benefits Policy that was attached as Exhibit 1 to Resolution 2024-001, and that was thereby amended to add Juneteenth, was not the latest version of the Employee Benefits Policy. Exhibit 1 to Resolution 2024-001 inadvertently amended the Employee Benefits Policy that had been adopted by the SCPPA Board of Directors on May 16, 2019 through Resolution No. 2019-037. The version that should have been attached to Resolution 2024-001 and amended, is the Employee Benefits Policy that was adopted by the Board on September 19, 2019 and approved via Resolution No. 2019-112. The May 2019 and September 2019 versions of the Employee Benefits Policy contain different language in Section 1-2, Flexible Benefits Plan, Subsection A, Medical Insurance, regarding SCPPA's health plan premium contribution -- specifically, the Supplemental Contribution for Employee health insurance and the health plan allowance for employees who opt out. The differences between the May 2019 Policy and the September 2019 Policy are shown below.

<u>May 2019 Version</u> (older version adopted by Resolution 2019-037 and erroneously included in Resolution No. 2024-001)

Supplemental Contribution for Employees

The Supplemental Contribution for Employees, which is the difference between the second-lowest cost PERS Basic Monthly Rate for the employee's selected coverage tier and geographic area; and the PEMHCA Minimum Contribution.

[Paragraph omitted – no change between May 2019 and September 2019 Policy]

The health plan allowance for employees who opt-out is equal to the difference between the second-lowest cost PERS monthly health plan premium (i.e., Basic Monthly Rate schedule) for employee only coverage in the "Los Angeles Area" and the PEMHCA Minimum Contribution.

<u>September 2019 Version</u> (most recent language adopted by Board through Resolution 2019-112):

Supplemental Contribution for Employees

A Supplemental Contribution set by the SCPPA Board that, when added to the PEMHCA Minimum Contribution results in a medical insurance benefit within the range of benefits that the five mid-sized SCPPA Members provide to their employees; provided; that the SCPPA Board may set a different rate for employees who reside in a given geographical area to adjust for difference in Monthly Premiums for that area.

[Paragraph omitted – no change between May 2019 and September 2019 Policy]

The health plan allowance for employees who opt-out is set by the Board during the annual budget approval.

SCPPA staff recommends adopting the proposed Resolution to correct the administrative error in Resolution 2024-001 and retain the health plan premium contribution and health plan opt-out allowance wording that was adopted by the Board through Resolution 2019-112.

In order to prevent such version control issues in the future, SCPPA staff has added a Version History table to the SCPPA Employee Benefits Policy and will be adding version history tables to all other SCPPA policies.

SCPPA's Authority:

SCPPA has the authority for this proposed action under the California Joint Exercise of Powers Act and the SCPPA Joint Powers Agreement.

FISCAL IMPACT:

There is no fiscal impact associated with the adoption of this Resolution.

ATTACHMENTS:

1. Resolution No. 2024-012

RESOLUTION NO. 2024-012

RESOLUTION OF THE BOARD OF DIRECTORS OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY AMENDING RESOLUTION NO. 2024-001 REGARDING THE EMPLOYMENT BENEFITS POLICY AND ADDING JUNETEENTH AS A PAID SCPPA HOLIDAY

WHEREAS, the Southern California Public Power Authority ("SCPPA" or "the Authority") Through its Resolution 1993-31, adopted an Employee Benefits Policy (as amended from time to time, the "Policy"), which Policy has subsequently been amended through Resolution Nos. 2003-16, 2008-24, 2014-132, 2016-069, 2016-095, 2018-086, 2019-037, and 2019-112; and

WHEREAS, the Policy sets forth the schedule of SCPPA holidays; and

WHEREAS, on January 18, 2024, the Board of Directors adopted Resolution No. 2024-001, adding Juneteenth to the schedule of paid SCPPA holidays, and said Resolution attached and incorporated a revised version of the Policy adding the Juneteenth holiday; and

WHEREAS, Resolution No. 2024-001 erroneously and inadvertently attached and revised an outdated version of the Policy, namely, the Policy that had been adopted on May 16, 2019 via Resolution No. 2019-037, which Policy contained superseded wording related to medical premiums; and

WHEREAS, Resolution No. 2024-001 should have attached and modified the Policy which was adopted by the Board on September 19, 2019, via Resolution No. 2019-112; and

WHEREAS, the Board of Directors desires to correct the error in Resolution No. 2024-001 and to attach the correct, revised version of the Policy, modified to add the Juneteenth holiday.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Authority, that Resolution 2024-001 is hereby amended nunc pro tunc by replacing Exhibit 1 to said Resolution 2024-001 with Exhibit 1 to this Resolution No. 2024-012. All references in Resolution 2024-001 to "Exhibit 1" refer to Exhibit 1 to this Resolution No. 2024-012.

THE FOREGOING RESOLUTION is approved and adopted by the Authority this 18th day of April, 2024.

____

PRESIDENT
Southern California Public
Power Authority

ATTEST:

____

RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

EXHIBIT 1 to RESOLUTION No. 2024-012
and
Replacement EXHIBIT 1 to RESOLUTION No. 2024-001

SCPPA EMPLOYEE BENEFITS POLICY

Revision History:

Date	Action
November 18, 1992	SCPPA Employee Benefits Policy (Policy) adopted by SCPPA Board of Directors (Board) Resolution No. 1993-31
May 15, 2003	Policy revised by Board Resolution No. 2003-16
May 15, 2008	Policy revised by Board Resolution No. 2008-24
December 18, 2014	Policy revised by Board Resolution No. 2014-132
October 20, 2016	Board adopted Resolution No. 2016-095 Revising the Method for Determining the Authority's Supplemental Contribution Toward Payment of Premiums for Medical Insurance for SCPPA Employees
August 16, 2018	Policy revised by Board Resolution No. 2018-086
May 16, 2019	Policy revised by Board Resolution No. 2019-037
September 19, 2019	Policy revised by Board Resolution No. 2019-112
January 2024	Policy revised by Board Resolution No. 2024-001
[April 18, 2024] [proposed action]	[Board Resolution No. 2024-012 correcting error in Resolution No. 2024-001 and attaching correct version of revised Policy; effective January 18, 2024]

Southern California Public Power Authority
Employee Benefits Policy
[Adopted: April 18, 2024; Effective January 18, 2024]
RESOLUTION NO. 2024-012

SCPPA's Employee Benefits are established and modified by the SCPPA Board of Directors (Board) by Resolution. The Board shall retain full discretion to review, revise, repeal, or make changes to employee benefits to the fullest extent permitted by law. The Board has no intent to create any vested right to any employee benefit, including pension and retiree health benefits. New employees shall be required, as a condition of employment, to affirmatively acknowledge that they have been informed of the Board's rights and intent with respect to SCPPA's employee benefits.

1-1. Benefits Eligibility

Employee benefits described in this Policy are available only to full-time employees (Eligible Employees). As used herein, a full-time employee is an employee who regularly works 40 hours per week, or such shorter number of hours as may be prescribed by applicable law.

1-2. Flexible Benefits Plan

SCPPA's Flexible Benefits Plan (i.e., an IRC section 125 Cafeteria Plan) effective on January 1, 2015. The Flexible Benefits Plan allows Eligible Employees to choose from a variety of benefits to formulate a plan that best suits their needs. The Flexible Benefits Plan includes the following components:

A. Medical Insurance

SCPPA participates in the State of California Public Employees' Retirement System's (PERS) Health Benefits Program as a public agency under the Public Employees' Medical and Hospital Care Act (PEMHCA). Under the PERS Health Benefits Program, Eligible Employees may select an eligible health plan of their choice from Health Maintenance Organization (HMO), Preferred Provider Organization (PPO), and traditional insurance plans.

The monthly health plan premiums for each calendar year are established by PERS, which publishes the costs in a report titled "Monthly Premiums for Contracting Agencies" (Monthly Premiums). SCPPA may pay for all or part of the monthly health plan premium for the employee's selected health plan. Should the premium cost of the PERS health plan selected by the employee exceed SCPPA's payment, the employee will be responsible for paying the difference through a payroll deduction.

SCPPA's contribution to fund employee health plan premiums may vary depending on certain circumstances, such as the selected health plan provider, geographic area, and/or coverage tier selected by the employee (i.e., employee only, employee plus one dependent, or employee plus two or more dependents). SCPPA's health plan premium contribution consists of two components that are subject to annual adjustment, as follows:

- **PEMHCA Minimum Contribution**

  A PEMHCA minimum employer contribution as set annually by the PERS Board of Directors; and

- **Supplemental Contribution for Employees**

  A Supplemental Contribution set by the SCPPA Board that, when added to the PEMHCA Minimum Contribution, results in a medical insurance benefit within the range of benefits that the five mid-sized SCPPA Members provide to their employees; provided, that the SCPPA Board may set a different rate for employees who reside in a given geographical area to adjust for differences in Monthly Premiums for that area.

  An employee may elect not to participate in (opt-out of) the SCPPA sponsored PERS Health Benefits Program. An employee who opts-out of health insurance coverage is eligible for a health plan allowance that can be: (i) used to enhance other benefit coverage, (ii) used to fund other benefits included in the Flexible Benefits Plan, and/or (iii) taken as a taxable cash payment.

  The health plan allowance for employees who opt-out is set by the Board during the annual budget approval.

  Open enrollment for the PERS Health Benefits Program occurs once per year. Elections made will apply to the following calendar year, during which employees will not be able to change their election except in limited circumstances and qualified life events.

B. Group Dental and Vision Insurance

SCPPA provides a group dental and vision plan (Plan) open to all employees and their families. All employees are required to enroll in the Plan regardless of whether they elect to enroll family members. SCPPA will cover up to the cost of the Employee plus Family monthly premium if the employee elects to enroll in the family plan.

C. Health Flexible Spending Account (HFSA)

SCPPA offers a HFSA under which employees may elect to set aside part of their SCPPA pay each calendar year on a pre-tax basis, for reimbursement of certain medical, dental, and/or vision expenses that are not covered by the employees' medical, dental, and vision insurance plans.

This externally administered benefit enables employees to reduce the cost of allowable health-related expenses. SCPPA does not make or match any contributions to the HFSA.

D. Dependent Care Flexible Spending Account (DFSA)

SCPPA offers a DFSA under which employees may elect to set aside part of their SCPPA pay each calendar year on a pre-tax basis, for reimbursement of certain dependent day care expenses. Typically, these would be day care expenses for children, but may also be used to reimburse day care for other dependents, such as spouses, parents, or grandparents, who cannot care for themselves.

The DFSA is an externally administered benefit that enables employees to reduce the cost of allowable dependent care expenses. SCPPA does not make or match any contributions to the DFSA.

1-3. Other Employee Benefits

A. Group Life Insurance

SCPPA pays the premium costs for a group term-life, and accidental death and dismemberment (AD&D) insurance policy equal to an eligible employee's annual salary up to $250,000.00 (or the maximum coverage available, whichever is less). Coverage under SCPPA's life and AD&D group insurance policy is subject to certain age reductions set forth in the provider’s policy.

B. Group Disability Insurance

SCPPA's disability insurance program is integrated, thereby, eliminating overlapping coverage and providing a seamless transition from short- to long-term disability. SCPPA's disability insurance program is designed such that benefits paid to employees are not subject to income taxes.

SCPPA's short-term disability (STD) group insurance policy pays 60% of an employee's monthly salary (or the maximum coverage available, whichever is less), less income from other sources such as social security, state disability, workers' compensation, or government retirement systems. There is a 7-day elimination period. The employee shall exhaust all accrued Universal Leave prior to receiving any disability benefit for the remainder of the STD benefit elimination period.

SCPPA's long-term disability (LTD) group insurance policy pays 60% of and employee's monthly salary (or the maximum coverage available, whichever is less), less income from other sources such as social security, state disability, workers' compensation, or government retirement systems. There is a 90-day elimination period.

Coverage under SCPPA's disability insurance program is subject to certain age restrictions set forth in the policy. SCPPA employees are responsible for paying the insurance premium cost for STD insurance, but not LTD insurance.

C. Deferred Compensation Plan

SCPPA offers a deferred compensation plan (i.e., 457(b) Plan), under which Eligible Employees may elect to contribute part of their SCPPA salary on a pre-tax basis. The plan thereby enables employees to accumulate retirement savings on a pre-tax basis. SCPPA will match employee contributions at an amount approved by the SCPPA Board as part of the annual budgeting process.

D. Tuition Reimbursement

Eligible Employees will be reimbursed after completion of the course with a letter grade of “C” or numerical grade of 2.0, or better, for costs of tuition and books for pre-approved courses of study at the rate equal to 75%, up to a maximum of $3,500.00 per year. This benefit is at the discretion of SCPPA's Executive Director.

1-4. Retirement Benefits

A. Pension Plan

SCPPA provides Eligible Employees with retirement benefits under the State of California's pension plan, the California Public Employees' Retirement System (PERS). The terms and conditions of these benefits are set out in a contract between SCPPA and PERS.

Both SCPPA and Eligible Employees contribute toward the cost of the PERS benefit. Employee contributions are deducted from employees' base pay through bi-weekly payroll deductions, which are exempt from income taxes (but are subject to Medicare taxes).

An employee's contributions and benefit levels under PERS depend on whether the employee is a "Classic Member" or “PEPRA Member” as defined below.

- **Classic Member**

  “Classic Member” means any PERS-covered SCPPA employee who either: (i) before 2013, was an active member in PERS while employed by SCPPA, or (ii) becomes a SCPPA employee on or after January 1, 2013, and has, within the six months preceding the employment date, received service credit under PERS or under a reciprocal retirement system.

  Classic Members are covered by PERS's 2.5% @ 55 formula. The benefit for SCPPA service is calculated using the employee's highest 12 consecutive months of pensionable compensation. Classic Members shall pay employee contributions toward their PERS benefit equal to 8.0% of the employee's pensionable compensation.

- **PEPRA Member**

  “PEPRA” refers to the Public Employees Pension Reform Act of 2013. “PEPRA Member” means any PERS-covered SCPPA employee who is not a Classic Member. PEPRA Members are covered by PERS's 2.0% @ 62 formula. The benefit for SCPPA service is calculated using the highest 36 consecutive months of pensionable compensation.

  PEPRA Members must pay employee contributions toward their PERS benefit. Under PEPRA, the required contribution amounts are generally tied to the annual actuarial cost associated with the benefits earned. PERS establishes the required contribution annually.

  PEPRA also establishes a cap on pensionable compensation which is subject to annual adjustment by the PERS Board.

SCPPA does not withhold or contribute Social Security tax on behalf of its employees.

B. Retiree Medical Insurance

Active employees who retire from SCPPA and receive a PERS pension are eligible to participate in the PERS Health Benefits Program described above. The monthly premium costs for each calendar year are established by PERS, which publishes the costs in a report titled "Monthly Premiums for Contracting Agencies". Premiums may differ for retirees and active employees, especially if the retiree is eligible to receive Medicare.

SCPPA may pay for all or part of the monthly health plan premium of the retiree's selected health plan for the single-individual only coverage tier. Should the premium cost of the PERS health plan selected by the retiree exceed SCPPA's payment, the retiree will be responsible for paying the difference.

SCPPA's contribution to fund retiree medical insurance premiums may vary depending on certain circumstances, such as the health plan provider, geographic area, and/or age. SCPPA's health plan premium contribution consists of two components which are subject to annual adjustment, as follows:

- **PEMHCA Minimum Contribution**

  A PEMHCA minimum employer contribution as set annually by the PERS Board of Directors; and

- **Supplemental Contribution for Eligible Retired Employees**

  SCPPA provides a Supplemental Contribution for Eligible Retired Employees. For this purpose, “Eligible Retired Employee” means an employee who (i) retires within 120 days after his or her last day of SCPPA employment, and (ii) who was either hired by SCPPA before December 18, 2014, or has completed at least ten (10) years of employment with SCPPA at the time of retirement.

  The Supplemental Contribution is an amount approved by the SCPPA Board as part of the annual budgeting process. The monthly Supplemental Contribution for Eligible Retired Employees (“Supplemental Contribution”) for those who retire on or after January 1, 2015 is the difference between an amount not exceeding the lowest cost PERS Basic Monthly Rate (or Supplemental/Managed Medicare Monthly Rate for retirees 65 years of age or older) for the single-individual only coverage tier applicable to the geographic region in which the retiree resided immediately prior to retirement and the PEMHCA Minimum Contribution.

  The monthly Supplemental Contribution for employees who retired from SCPPA prior to January 1, 2015 is equal to the lesser of the applicable PERS Basic Monthly Rate (i.e., retirees less than 65 years of age) or Supplement/Managed Medicare Monthly Rate (i.e., retirees 65 years of age or older) for their current health plan for the retiree only coverage tier; and the PEMHCA Minimum Contribution.

The SCPPA Board, in its sole discretion, (i) may elect to use the same methodology currently used for determining the amount of SCPPA’s Supplemental Contribution, with or without modification; (ii) may elect to change the current methodology and instead make the Supplemental Contribution in the form of a fixed dollar amount that may be more or less than the amount paid in previous years, or (iii) may reduce the amount of the Supplemental Contribution to zero.

Eligible Retired Employees that elect not to participate in the SCPPA-sponsored PERS Health Benefits Plan will not be entitled to any SCPPA health premium contributions (i.e., the PEMHCA Minimum Contribution and the Supplemental Contribution).

1-5. Paid Time Off

A. Universal Leave

Time-off (i.e., including sick and vacation time) taken by an employee regardless of the reason is considered to be "Universal Leave". Employees accrue Universal Leave hours based on the employees' years of service with SCPPA or as otherwise approved by the SCPPA Board, as set forth in the following table:

Service Year	1 - 5	6	7	8	9	10	11	12	13	14	15
Universal Leave Hours	176	184	192	200	208	216	224	232	240	248	256

- **Maximum Accrual**

  Each employee shall be allowed to accrue a maximum of 1,000 hours of Universal Leave at any time. If an employee's accrued balance exceeds 1,000 hours, they will stop accruing universal leave until such time that their balance falls below 1,000 hours.

- **Cash-Out Option**

  With the approval of the Executive Director, employees may cash-out Universal Leave at 100% of the current value, up to 200 hours at any time once each calendar year, provided that their Universal Leave balance does not fall below 400 hours following the cash-out and the employee must also have used at least 80 hours of Universal Leave in the last twelve (12) consecutive calendar months.

- **Payout Upon Separation or Death**

  Accrued, unused Universal Leave shall be paid to an active employee upon separation at 100% of the cash-out value, unless otherwise required by law.

  Upon the death of an active employee, the accrued unused Universal Leave shall be paid to the employee's beneficiary at 100% of the cash-out value, regardless of service time.

- **Universal Leave Donations**

  In limited circumstances, an employee may elect to donate part of his or her Universal Leave balance to another employee. A donation is only permitted to provide additional Universal Leave to an employee who becomes ill and requires leave for an extended period of time that exceeds his or her Universal Leave balance. Universal Leave may be donated to such employee's Universal Leave bank on a per dollar equivalency equal to the time donated by the other employee(s).

B. Holidays

Employees will be paid for the following holidays:

New Year's Day (January 1st)
Martin Luther King, Jr. Day (3rd Monday in January)
President's Day (3rd Monday in February)
Memorial Day (Last Monday in May)
Juneteenth (June 19th)
Independence Day (July 4th)
Labor Day (1st Monday in September)
Columbus Day (2nd Monday in October)
Veterans' Day (November 11th)
Thanksgiving Day (4th Thursday in November)
Day after Thanksgiving (Friday after 4th Thursday in November)
Christmas Day (December 25th)
One (1) Floating Holiday

When holidays fall or are celebrated on a regular workday, eligible full-time employees shall receive one (1) day's pay at their regular straight-time rate. Full-time employees who are exempt from the Fair Labor

Standard Act who are called into work on a holiday will receive one (1) day's pay at their regular straight-time rate, and an additional payment of straight time for the actual time they work that day.

For holidays that fall on a scheduled day-off, SCPPA will post a schedule each calendar year showing which days such holidays will be observed in lieu by employees.

The Executive Director shall establish the floating holiday each calendar year.

C. Administrative Leave

At the discretion of the Executive Director, up to five days of paid Administrative Leave may be granted annually.

D. Bereavement Leave

An employee shall be entitled to be absent from work with pay in the event of the death of a member of his or her immediate family. Pay shall be authorized for all or any portion not to exceed three (3) days of such leave provided a written request for such pay is filed. Any absence in excess of three (3) days shall be in accordance with the existing provisions.

For purpose of this Section the term "member of the immediate family" is limited to any relative by blood or marriage who is a member of the employee's household; and parents, step-parents, spouse, registered domestic partner, children, step-children, brother, sister, grandparents, grandchildren, great grandparent, great grandchild, son/daughter-in-law, father/mother-in-law, sister/brother-in-law, grandfather/grandmother-in-law or responsible guardian or person who has acted in that capacity, regardless of place of residence.

E. Jury Duty

Employees ordered to perform jury service or subpoenaed to court or any legislative body shall be entitled to a leave of absence with pay for the entire day for each day served, and without deduction from Universal Leave, at an amount equal to the employee's regular daily earnings. In the case of subpoena leave, the employees are eligible if the appearance time occurs during their normal working hours, and they are not a party to the suit.

The term regular earnings means full pay for regularly scheduled work, which the employees would have received had they not been called to jury service or subpoenaed.

Employees shall account for all time spent on jury duty or subpoena leave. If employees are excused from jury service or subpoena on a normal workday, they are expected to report for work. Employees must account to their departments for any time off for illness or other reasons, while on jury duty or subpoena leave.

Upon completion of jury service or subpoenaed time, the employees upon receipt, shall submit to SCPPA the jury fees, witness fees and/or mileage fees and a copy of the court report of jury time served. When employees are served with a subpoena, the employees shall request witness fees. The employees shall retain or be reimbursed the amount paid by the court for mileage and jury fees representing jury service performed by the employees on their regular day off.

1-6. Leave Without Pay

A. Protected Leave

If an Eligible Employee has no other leave available, SCPPA will grant a personal leave of absence without pay consistent with Federal and State Law as required under the Family and Medical Leave Act, California Family Rights Act, Pregnancy Disability Leave Law, or Americans with Disabilities Act.

SCPPA will continue health insurance coverage during the protected leave if the employee pays the employee share of the monthly premium and payments are submitted to SCPPA in a timely manner.

Universal Leave will not be accumulated, and Holidays will not be paid.

SCPPA is not obligated to reinstate the employee to the same position, only an equivalent position upon return to work.

Protected leave runs concurrently with any STD and LTD Leave of Absence.

B. Unprotected Personal Leave

If an Eligible Employee has a need to be absent from work and who is not eligible for leave with pay, SCPPA's Executive Director may grant a personal leave of absence without pay up to 120 days. A written request for a personal leave is required at least two (2) weeks before the anticipated start of the leave. Leave approval is subject to consideration of staffing requirements, the reasons for the requested leave, and employee performance, and attendance. The SCPPA Executive Director may require supporting documentation from the employee before granting the request. Leaves of absence greater than 120 days require SCPPA Board approval. Personal leave may be extended if prior to the end of the leave a written request for an extension is submitted and approved by the Executive Director or SCPPA Board, as applicable. During personal leave,

Universal Leave will not be accumulated, and Holidays will not be paid.

During personal leave, SCPPA will continue health insurance coverage if the employee pays the full monthly premium and payments are submitted to SCPPA in a timely manner.

SCPPA is not obligated to reinstate the employee to the same position, only an equivalent position upon return to work.

Failure to advise management of availability to return to work, failure to return to work when notified, or continued absence from work beyond the time approved by SCPPA, will be considered a voluntary resignation of employment.

Personal leave runs concurrently with any STD and LTD.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
1160 NICOLE COURT
GLENDORA, CA 91740
(626) 793-9364
WWW.SCPPA.ORG

MEMO

TO: SCPPA Board of Directors

FROM: Randolph R. Krager, Acting Executive Director

DATE: Thursday, April 11, 2024

RE: Working Group Updates

WORKING GROUP SUMMARY

ASSET MANAGEMENT

The Asset Management Working Group last met on January 25, 2024. The next meeting is scheduled for May 9, 2024.

ASSISTANT GENERAL MANAGER (AGM)

The AGM Working Group last met on January 24, 2024. The next meeting will be held on April 24, 2024.

CYBERSECURITY

The Cybersecurity Working Group (CWG) did not meet this month. The CWG meets on an ad-hoc basis.

FINANCIAL INCENTIVES and RATES

The Financial Rates and Incentives group met on March 19, 2024; at which time the members updated the “Action Item Priority” list. The list is intended to guide group discussions, amongst the twelve SCPPA members, and address rate-related issues impacting a wide range of programs. The results are used to assist members benchmark their efforts as well as assist other members in improving their programs’ performance.

The next meeting is scheduled for April 19, 2024.

KEY ACCOUNTS

This group meets on an ad hoc basis, and a future meeting is currently not scheduled.

LEGAL

The Legal Working Group met on March 28, 2024, to discuss a draft pro forma agreement for renewable projects. A subgroup will meet in late April to continue the discussion. The next quarterly meeting is scheduled for June 27, 2024.

LEGISLATIVE

At the March 20, 2024 meeting the Legislative Working Group (LWG) discussed the status of the Inflation Reduction Act’s direct pay regulations; the governor’s proposal to increase the Energy Resources Programs Account surcharge; and newly introduced bills, including measures on pole attachments (AB 2221, Carrillo) and net energy metering (AB 2619, Connolly; AB 2256, Friedman). The LWG also received updates on SCPPA’s draft transformer legislative resolution; cap and trade issues; SCPPA’s post-Capitol Day meetings; CalETC issues; the March 19 SCPPA-led POU meeting with CEC Vice Chair Gunda’s senior advisors; and the July 10-12 SCPPA Policy Staff Tour

At the April 4, 2024, meeting, the LWG discussed SCPPA’s lobbying efforts regarding AB 2221 (referenced above), which establishes strict shot clock requirements for broadband pole attachments on utility poles. The LWG also discussed positions and amendments related to measures on energy storage targets (SB 1508, Stern); the creation of the Climate

Equity Trust Fund (AB 2329, Muratsuchi); county sealers' authority to inspect public agencies' EV chargers; biomass mandates (SB 1062, Dahle); and AB 1373 cleanup (AB 1834, Garcia).

The next LWG will be on April 17, 2024.

MUTUAL ASSISTANCE

The Mutual Assistance Sub-working Group (MAWG) met on April 2, 2024. The MAWG suggested conducting a tabletop exercise in the future at the SCPPA Training Center or at a Member's Utility Facility. California Utilities Emergency Association (CUEA) is reaching out to Utilities to create a Joint Task Force. CUEA will be discussing this topic at their annual meeting on May 10, 2024.

The next MAWG meeting is scheduled for May 7, 2024.

NATURAL GAS

The Natural Gas Working Group last met virtually on January 23, 2024. The next working group meeting is scheduled for April 23, 2024.

CUSTOMER PROGRAMS

The Customer Programs Group met on April 3, 2024, where the group recapped the recently received "Solicitation and Contracts Management" training. SCPPA staff answered questions concerning the training that the members asked. The group also discussed the CMUA co-funding agreement. They were informed by SCPPA Staff that "Letters of Participation" would be sent to each member to obtain signature authorization from each Member's General Manager. In addition, SCPPA vendor, Energy Federation, Inc. (EFI), provided a presentation to the group where they introduced their new Demand Response and Energy Efficiency program services.

Finally, the group was informed by SCPPA Staff that the EE Potential Study RFP had closed and that volunteer evaluators would be contacted within two weeks to begin the evaluation process.

The next meeting for the Customer Programs Group is scheduled for May 1, 2024.

REGULATORY

The Regulatory Working Group (RWG) met on March 20, 2024 and April 4, 2024.

The RWG discussed matters at the California Air Resources Board (CARB), California Energy Commission (CEC), California Independent System Operator (CAISO), and California Electric Transportation Coalition (CalETC).

The RWG remained focused on matters at CARB. Members discussed and prepared for meetings with the Joint Utility Group (JUG) and CARB regarding Cap-and-Trade rulemaking impacts to utility allowances. While the formal rulemaking has not kicked off yet, CARB has indicated that it will be completed by the end of 2024. Additionally, the RWG discussed the Advanced Clean Fleets (ACF) rule and proposed changes resulting from the SCPPA-sponsored bill, AB 1594. SCPPA Members provided input for comments to be submitted in April 2024.

The RWG also discussed matters at the CEC, including grant funding programs available for POUs. In addition, the RWG discussed CAISO updates on the West-Wide Governance Pathways Initiative and CalETC engagement.

The next RWG meeting is scheduled for April 17, 2024.

RENEWABLES

The Renewables Working Group (ReWG) met on March 19, 2024. The ReWG discussed the ongoing 9 developing projects. SCPPA plans to have a video instructional session with PFM in late April or early May discussing SCPPA's Inflation Reduction Act Financial Model that PFM helped create. An IRA Workshop with presenters from Nixon-Peabody, PFM, and Black & Veatch will be held virtually on April 30, 2024.

The next ReWG meeting is scheduled for April 16, 2024.

RESOURCE PLANNING

The Resource Planning Working Group (RPWG) met on April 4, 2024. The RPWG discussed the market updates provided by SCPPA affecting the energy sector for both the power and natural gas markets. SCPPA posted the 2024 Standalone Storage RFP on March 29, 2024. We expect a couple of vendors to submit their proposals to the newly released RFP in the next few weeks. Glendale volunteered to present their Integrated Resource Plan (IRP) updates to the group in July.

The next RPWG meeting is scheduled for May 2, 2024.

RISK MANAGEMENT

The Risk Management Working Group (RMWG) held its monthly meeting on Wednesday, April 3. During the meeting, the Group received a presentation from S&P Global on its Power Forecasting Model. This subscription-based model from S&P offers members access to a wide range of tools. These tools encompass project tracking data, financials, forecasting, and commodity pricing. Additionally, the model provides the option for customizable reports tailored to the specific needs of each Member.

The next meeting is scheduled for May 1, 2024.

SAFETY

The Safety Working Group (SWG) did not meet this month. The SWG meets on an ad-hoc basis.

TRANSPORTATION ELECTRIFICATION

The Transportation Electrification Working Group (TEWG) met April 10, 2024. During that meeting., Members elected to listen, as a group, to the Low Carbon Fuel Standard (LCFS) Workshop which was conducted by CARB. TEWG also discussed the EVSE RFP and began to develop the RFP evaluation matrix. TEWG received a legislative update from the SCPPA Regulatory Affairs team regarding the Advanced Clean Fleets (ACF) rule.

The next meeting is scheduled for May 8, 2024.

TRANSMISSION & DISTRIBUTION ENGINEERING & OPERATIONS (T&D E&O)

The Transmission & Distribution Engineering & Operation Working Group (T&D WG) met on April 2, 2024. The T&D WG received the overall System Reliability Studies Presentation from Pandora this month. It was informative to see where the Members rated compared to their peers in the Utility space for 2022. Pandora will begin working on 2023 studies for the 2024 Report later this year, also with a presentation to the T&D WG to follow. In addition, the expected date for the 2024 T&D E&O Annual Conference will be on November 6, 2024.

The next T&D WG meeting is scheduled for May 7, 2024.

DEMAND RESPONSE & REDUCTION SUB-WORKING GROUP (DRRWG)

The Demand Response & Reduction Sub-Working Group (DRRWG) met for its inaugural meeting on March 27, 2024. The DRRWG was well attended by all SCPPA Members. Each Member shared information about their utility's current and/or future Demand Reduction/Response Programs. During the meeting, Members asked other Members detailed questions about how their internal DR programs, as well as the partner relationships (i.e., vendors, product suppliers, etc.) necessary to make the program successful.

The next DRRWG meeting has not been scheduled yet.

RECURRING/ROLLING SOLICITATIONS:

NAME: Request for Proposals: 2024 SCPPA Renewables Energy Resources and Energy Storage Solutions

WORKING GROUP: Renewables

ISSUE DATE: February 1, 2024 **CLOSE DATE:** June 27, 2024

DESCRIPTION:

SCPPA's semi-annual rolling RFP to solicit proposals from developers for renewable resources with or without energy storage (Solar, Wind, Geothermal, Biomass, and Small Hydro) utilizing the Inflation Reduction Act to meet Members' IRP and RPS goals.

NAME: Request for Proposals: 2024 Stand-Alone Energy Storage Systems

WORKING GROUP: Resource Planning

ISSUE DATE: March 29, 2024 **CLOSE DATE:** December 31, 2024

DESCRIPTION:

SCPPA Members seek Stand-Alone Energy Storage Systems (ESS) to support Members' procurement of renewable resources in meeting their Renewable Portfolio Standards (RPS) and procurement targets regarding Assembly Bill (AB) 2514. This RFP seeks proposals for stand-alone ESS in areas relevant to SCPPA Members' territories (CAISO Balancing Authority (BA), IID BA, and at specific locations within the LADWP BA system).

UPCOMING/RECENT SOLICITATIONS (NEW/CONTINUED SERVICES):

NAME: Electric Vehicle Supply Equipment and Services

WORKING GROUP: Transportation Electrification

ISSUE DATE: (Tentative) **CLOSE DATE:** (Tentative)

DESCRIPTION:

Solicitation for the provision of EVSE Services (EV Charger Installation, Design and Build, Back Office Support Services, Operation and Maintenance, and EV Equipment Replacement Parts)

NON-BOARD APPROVED CONTRACT EXTENSIONS:

NONE

DocuSigned by:

Randolph R. Krager

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Randolph R. Krager, Acting Executive Director
Southern California Public Power Authority

SCPPA Southern California Public Power Authority

AGENDA ITEM STAFF REPORT

MEETING DATE: April 18, 2024

RESOLUTION NUMBER: 2024-014 2024-015

SUBJECT: Issuance of Southern Transmission System (STS) Renewal Project Revenue Bonds, 2024-1 - Second Tranche

DISCUSSION: ☒ **OR** **CONSENT:** ☐

Select the appropriate box(es):

FROM:		**METHOD OF SELECTION:**	
Finance	☒	Competitive	☐
Project Development	☐	Cooperative Purchase	☐
Program Development	☐	Sole Source	☐
Regulatory/Legislative	☐	Other	☒
Project Administration	☐	*Other (Please describe):*	
Legal	☐	In accordance with SCPPA Policy for Financing and Selection of Financing Team	
Executive Director	☐		

MEMBER PARTICIPATION:

Sponsoring Member: LADWP, Burbank and Glendale

Other Members Potentially Participating: None

Approved by Acting/Interim Executive Director: DocuSigned by: Randolph R. Krager 40619458107B4D2...

RECOMMENDATION:

Adopt Resolution Number 2024-014 authorizing the issuance of the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 and the execution and delivery of various agreements relating to the issuance of the project revenue bonds and Resolution Number 2024-015 approving the provision of certain Continuing Disclosure information with respect to the project revenue bonds.

BACKGROUND:

The Intermountain Power Agency (IPA) has plans for capital improvements to the Southern Transmission System (STS) that include the construction of new transformers and the replacement, renewal and expansion of converter stations, AC switchyards and associated facilities. These improvements are known as the STS Renewal Project. Components of these planned upgraded facilities are currently scheduled to enter service from May 2024 through April 2028. The total estimated cost of the project is $2.66 billion.

SCPPA Member participants of the STS Renewal Project are LADWP, Burbank, and Glendale (Project Participants).

DISCUSSION:

The Project Participants desire SCPPA to provide the financing of the STS Renewal Project with payments-in-aid of construction to IPA. All necessary agreements between SCPPA and IPA and between SCPPA and Project Participants to provide for the financing of the STS Renewal Project are in place.

The financing plan anticipates issuing bonds in multiple tranches instead of one upfront issuance to reduce the amount of capitalized interest and debt service. The first tranche of bonds was issued in April 2023 with the issuance of the Southern Transmission System Renewal Project, Revenue Bonds, 2023-1 and 2023-1A, for $254,695,000 and $431,495,000, respectively. The latest construction spending forecast anticipates the need for additional bond proceeds in August 2024.

The proposed financing plan is for the issuance of the second tranche of bonds. The plan anticipates issuing fixed rate tax-exempt project revenue bonds for a 29-year term with approximately level aggregate debt service (when combined with the 2023-1 and 2023-1A bonds) to cover the estimated construction spending from August 2024 to June 2025, which is currently estimated at $520 million.

Currently, it is anticipated that the second tranche of bonds (2024-1 Bonds) will be priced the week of April 22, 2024, with the transaction closing in early May 2024.

On February 15, 2024, the Board of Directors adopted Resolution No. 2024-008 authorizing the preparation of all documents necessary for the sale and issuance of the second tranche of project revenue bonds for the STS Renewal Project.

The first Resolution, 2024-014, (Authorizing Resolution) attached will authorize the issuance of the project revenue bonds and the execution and delivery of various documents relating to the issuance of the bonds, including those attached to this report. The second Resolution, 2024-015, (Continuing Disclosure Resolution) attached will authorize provision for certain Continuing Disclosure information with respect to the project revenue bonds. The Finance Committee recommended approval of the two Resolutions at the April 4, 2024 Finance Committee meeting.

- **Selection Method:**

  The financing team has been assembled and consists of SCPPA staff, Project Participants' staff, Norton Rose Fulbright US LLP serving as Bond Counsel and Disclosure Counsel, Nixon Peabody LLP serving as Special Tax Counsel, and PFM Financial Advisors LLC serving as Financial Advisor.

  The Finance Committee recommended the selection of Barclays Capital Inc. as the senior managing underwriter and RBC Capital Markets as the co-senior manager, with BofA Securities, Inc., Loop Capital Markets LLC, Samuel A. Ramirez & Co., Inc., Siebert Williams Shank & Co., LLC, and TD Securities (USA) LLC as co-managers. The senior, co-senior, and co-managers were selected from SCPPA's established underwriting pool. The Finance Committee considered the qualification criteria as provided in SCPPA's Policy for Financing and Selection of the Financing Team taking into consideration the firm's experience and coverage of SCPPA and provided its recommendation on the firms that will deliver the overall best value for the transaction.

  An additional member of the financing team is US Bank, serving as Trustee/Paying Agent. Fees for services will be paid from bond proceeds.

- **Environmental Review:**

  The proposed resolution would authorize the preparation of documents for financing to fund the STS Renewal Project previously approved by the SCPPA Board and Project Participants. LADWP, as operating agent, has undertaken environmental review for the proposed project in accordance with the California Environmental Quality Act ("CEQA"). The Board's authorization of the issuance of bonds and related agreement and actions is exempt from CEQA under Section 15060(c)(3) ("project" definition) and under Section 15601(b)(3) of the CEQA Guidelines, the "common sense exemption," as it would not have a significant effect on the environment.

- **SCPPA's Authority:**

  The financing of the STS Renewal Project is in accordance with the California Joint Exercise of Powers Act and the SCPPA Joint Powers Agreement. The SCPPA Joint Powers Agreement provides the authority for SCPPA to finance generation and transmission projects.

FISCAL IMPACT:

The debt service for each component facility will start as each facility is placed in service. Interest during the construction period will be capitalized. Debt service payments from Project Participants under the Renewal Transmission Service Contracts will start after the transition date of June 16, 2027. Prior to the transition date, debt service payments will be billed to IPA under the Second Amendment to the STS Agreement, where in turn IPA will bill the six California participants in proportion to their respective capacity rights in the existing STS Project.

Exhibit A of the Authorizing Resolution provides good faith estimates of various financial information regarding the project revenue bonds to be issued, which include principal amount, true interest costs, finance charge, amount of proceeds, and total payment.

ATTACHMENT:

1. Resolution No. 2024-014 – Authorizing Resolution
2. Resolution No. 2024-015 – Continuing Disclosure Resolution
3. Third Supplemental Indenture of Trust
4. Purchase Contract
5. Preliminary Official Statement

[Project Vote: Burbank, Glendale and LADWP]

RESOLUTION NO. 2024-014

RESOLUTION RELATING TO THE SOUTHERN TRANSMISSION SYSTEM RENEWAL PROJECT AUTHORIZING: (I) THE ISSUANCE OF BONDS FOR THE SOUTHERN TRANSMISSION SYSTEM RENEWAL PROJECT, (II) THE EXECUTION AND DELIVERY OF (A)) A THIRD SUPPLEMENTAL INDENTURE OF TRUST RELATING TO THE SOUTHERN TRANSMISSION SYSTEM RENEWAL PROJECT, REVENUE BONDS, 2024-1, AND (B) A PURCHASE CONTRACT; (III) THE DELIVERY OF A PRELIMINARY OFFICIAL STATEMENT AND THE EXECUTION AND DELIVERY OF AN OFFICIAL STATEMENT; IV) CERTAIN RELATED ACTIONS; AND (V) THE OFFICERS, EXECUTIVE DIRECTOR AND CHIEF FINANCIAL AND ADMINISTRATIVE OFFICER OF THE AUTHORITY TO DO ALL OTHER THINGS DEEMED NECESSARY OR ADVISABLE

WHEREAS, the Southern California Public Power Authority (the “Authority”) has heretofore established the STS Renewal Project as an Authority project on behalf of the Los Angeles Department of Water and Power (“LADWP”) and the cities of Burbank and Glendale (together with LADWP, the “Project Participants”) to assist with financing the acquisition and construction of improvements to existing electric transmission facilities known as the Southern Transmission System (as so improved, the “Renewal Southern Transmission System”; such acquisition and construction and related acquisition of transmission capacity referred to herein as the “Southern Transmission System Renewal Project”); and

WHEREAS, the Authority has entered into (i) Renewal Agreements for the Acquisition of Capacity between the Authority and each Project Participant, (ii) Renewal Transmission Service Contracts between the Authority and each Project Participant and (iii) a Renewal Agency Agreement between the Authority and LADWP (collectively, the “STS Renewal Agreements”) each relating to the Renewal Southern Transmission System and the Southern Transmission System Renewal Project; and

WHEREAS, the Project Participants have requested that the Authority now authorize the issuance of the 2024-1 Bonds (as hereinafter defined) (i) to provide for the financing of a portion of the costs of the Southern Transmission System Renewal Project, (ii) fund capitalized interest, (iii) if determined to be necessary or desirable, make a deposit to a debt service reserve account for the 2024-1 Bonds, and (iv) pay the costs of issuance of such 2024-1 Bonds; and

WHEREAS, there has been presented to this meeting proposed forms of certain financing documents relating to the 2024-1 Bonds (as hereinafter defined); and

WHEREAS, LADWP, as operating agent, has undertaken environmental review and permitting for the proposed project in accordance with the California Environmental Quality Act (“CEQA”); and the Authority’s authorization of the issuance of bonds and related agreements and actions for the STS Renewal Project is exempt from CEQA under CEQA Guidelines Sections 15600(c)(3) (“project” definition) and 15601(b)(3) (the “common sense exemption”).

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Authority as follows:

1. Each of the President, any Vice President, Executive Director (references to Executive Director herein including any Interim Executive Director) and Chief Financial and Administrative Officer of the Authority (each, an "Authorized Representative") is hereby authorized to execute and deliver a Third Supplemental Indenture of Trust, dated as of May 1, 2024, from the Authority to the Trustee, relating to the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "2024-1 Bonds"), in the form on file with an Assistant Secretary of the Authority, with such changes, insertions and omissions (subject to Section 6 hereof) as shall be approved by said Authorized Representative to provide for the issuance and terms of said 2024-1 Bonds, such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof; and each of the Secretary and any Assistant Secretary is hereby authorized to attest thereto and to affix the seal of the Authority. The Third Supplemental Indenture of Trust, in the form in which executed and delivered, is hereinafter referred to as the "Third Supplemental Indenture," and shall supplement and amend the Indenture of Trust, dated as of April 1, 2023 (the "Original Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"). The Original Indenture, as heretofore supplemented and amended and as further supplemented and amended by the Third Supplemental Indenture is hereinafter referred to as the "Indenture." The form of Third Supplemental Indenture is hereby made a part of this Resolution as though set forth in full herein and the same hereby is approved.

The issuance of the 2024-1 Bonds is hereby authorized, subject to the provisions of this Resolution and the Indenture. The 2024-1 Bonds shall be dated, shall mature on the date and in the years and shall bear interest all as provided in the Indenture. The forms of the 2024-1 Bonds and the provisions for signatures, authentication, payment, registration, numbers, denominations, redemption (if any), sinking fund installments (if any), and other terms thereof shall be as set forth in the Indenture.

Proceeds of the 2024-1 Bonds will be used primarily to provide financing for (i) a portion of the cost of the Southern Transmission System Renewal Project pursuant to the terms of the STS Renewal Agreements, (ii) fund capitalized interest, (iii) if determined to be necessary or desirable, make a deposit to a debt service reserve account for the 2024-1 Bonds, and (iv) pay the costs of issuance of such 2024-1 Bonds.

The 2024-1 Bonds shall be secured by the pledge effected by the Indenture and shall be special, limited obligations of the Authority payable solely from the sources specified in the Indenture. Neither the State of California nor any public agency thereof (other than the Authority) nor the Project Participants nor any other member of the Authority shall be obligated to pay the principal or Redemption Price (as defined in the Indenture) of, or interest on, the 2024-1 Bonds. Neither the faith and credit nor the taxing power of the State of California nor any public agency thereof nor the Project Participants nor any other member of the Authority is pledged to the payment of the principal or Redemption Price of, or interest on, the 2024-1 Bonds. The 2024-1

Bonds shall not constitute a debt or indebtedness of the Authority within the meaning of any provision or limitation of the constitution or statutes of the State of California, and they shall not constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit.

2. Each of the Authorized Representatives is hereby authorized (i) to execute and deliver a purchase contract for the 2024-1 Bonds (the "Purchase Contract"), between the Authority and the senior manager (*i.e.,* Barclays Capital Inc.) as representative of itself and the other underwriters named therein (the "Underwriters") in the form on file with an Assistant Secretary of the Authority, with such changes, insertions and omission (subject to Section 6 hereof) as shall be approved by said Authorized Representative, such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof, and (ii) to negotiate the Underwriters' fee or discount relating to the 2024-1 Bonds. The purchase price at which the 2024-1 Bonds are to be sold to the Underwriters and the related Underwriters' discount shall each be determined in accordance with this Resolution. The form of Purchase Contract on file with an Assistant Secretary is hereby made a part of this Resolution as though set forth in full herein and the same hereby is approved.

3. Each of the Authorized Representatives is hereby authorized to approve a Preliminary Official Statement relating to the 2024-1 Bonds in the form on file with the Assistant Secretary of the Authority (such approval to be conclusively evidenced by the delivery thereof) (the "Preliminary Official Statement"), and the Board of Directors hereby approves the use of the Preliminary Official Statement in connection with the offering and sale of the 2024-1 Bonds, with such additions thereto and changes therein as are determined necessary or appropriate by such Authorized Representative to make such Preliminary Official Statement final as of its date, including, if applicable, for purposes of Rule 15c2-12 of the Securities and Exchange Commission (except for the omission of those items permitted to be omitted therefrom by said Rule). Each of the Authorized Representatives is authorized to deem the Preliminary Official Statement to be final within the meaning of such Rule 15c2-12. The Board of Directors hereby further approves the use of any supplement or amendment to the Preliminary Official Statement that is necessary or appropriate so that, in the opinion of an Authorized Representative (after consultation with the Authority's Disclosure Counsel), such Preliminary Official Statement does not contain any untrue statement of a material fact and does not omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which such statements were made, not misleading. The Underwriters are hereby authorized to distribute (including by electronic delivery) the Preliminary Official Statement to potential purchasers of the 2024-1 Bonds.

4. Each of the Authorized Representatives is hereby authorized to approve an Official Statement relating to the 2024-1 Bonds (such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof) (the "Official Statement"), and the Board of Directors hereby approves the use of the Official Statement in connection with the offering and sale of the 2024-1 Bonds. The Board of Directors hereby further approves the use of any supplement or amendment to such Official Statement that is necessary or appropriate so that, in the opinion of an Authorized Representative (after consultation with the Authority's Disclosure Counsel), such Official Statement does not contain any untrue statement of a material fact and does not omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which such statements were made, not misleading. Each of the Authorized Representatives is hereby authorized to execute the Official Statement and any amendment or

supplement thereto, in the name and on behalf of the Authority, and thereupon to cause such Official Statement and any such amendment or supplement to be delivered to the Underwriters. The Underwriters are hereby authorized to distribute (including by electronic delivery) the Official Statement and any such amendment or supplement thereto to the purchasers of the 2024-1 Bonds.

5. Each of the Authorized Representatives is hereby authorized to determine, in connection with the issuance and delivery of the 2024-1 Bonds, (i) whether to obtain municipal bond insurance for all or any portion of the 2024-1 Bonds, and if it is determined that municipal bond insurance shall be obtained, the particular provider or providers of municipal bond insurance with whom the Authority shall contract for such municipal bond insurance and (ii) whether to obtain a Debt Service Reserve Account Policy (as defined in the Indenture), if any debt service reserve account is to be funded, and if it is determined that a Debt Service Reserve Account Policy shall be obtained, the particular provider or providers thereof with whom the Authority shall contract for such Debt Service Reserve Account Policy. The premium to be paid with respect to any municipal bond insurance policy or any Debt Service Reserve Account Policy shall be approved by representatives of the Project Participants on the Authority's Finance Committee.

6. Each of the Authorized Representatives is hereby authorized to determine, in connection with the execution and delivery of the Indenture and the Purchase Contract, and the sale of the 2024-1 Bonds, and in consultation with the representatives of the Project Participants on the Authority's Finance Committee, the following:

(i) the aggregate principal amount of 2024-1 Bonds, which shall not exceed $1,000,000,000;

(ii) the interest rates of the 2024-1 Bonds, the true interest cost of which in the aggregate shall not exceed 6.00% per annum;

(iii) the maturity dates for the 2024-1 Bonds, with the final maturity being no later than July 1, 2054;

(vi) the principal amount of each maturity of the 2024-1 Bonds and the sinking fund amount (if any) for any term 2024-1 Bonds;

(vii) the purchase price of the 2024-1 Bonds;

(viii) the interest payment dates for the 2024-1 Bonds;

(ix) the terms and conditions for delivery of the 2024-1 Bonds;

(x) the redemption terms (if any) and prices of the 2024-1 Bonds;

(xii) the application of the proceeds of the 2024-1 Bonds and any other available moneys;

(xiii) whether or not to acquire municipal bond insurance in connection with the issuance of the 2024-1 Bonds, such determination to be made in accordance with Section 6 of this Resolution, provided the premium for such insurance shall not exceed 2% of the payments insured, calculated as provided in the bond insurance commitment agreement (or similar agreement) between the Authority and the provider of any such municipal bond insurance;

(xiv) in the event a debt service reserve account is to be funded in connection with the 2024-1 Bonds, whether or not to acquire a Debt Service Reserve Account Policy therefor, such determination to be made in accordance with Section 6 of this Resolution, provided the premium for such Debt Service Reserve Account Policy shall not exceed 3% of the amount of the debt service reserve requirement for the 2024-1 Bonds, calculated as provided in the Debt Service Reserve Account Policy commitment agreement (or similar agreement) between the Authority and the provider of any such Debt Service Reserve Account Policy; and

(xv) such other matters as may be determined by the Finance Committee.

7. Each of the President, any Vice President, Executive Director, Chief Financial and Administrative Officer, Secretary and any Assistant Secretary and any other officer or official of the Authority is hereby authorized to take any and all actions which such person deems necessary or advisable in order to effect the registration or qualification (or exemption therefrom) of the 2024-1 Bonds or any portion thereof, for issue, offer, sale or trade under the Blue Sky or securities laws of any of the states of the United States of America and in connection therewith to execute, acknowledge, verify, deliver, file or cause to be published any applications, reports, consents to service of process, appointments of attorneys to receive service of process and other papers and instruments which may be required under such laws, and to take any and all further actions which such person may deem necessary or advisable in order to maintain any such registration or qualification for as long as such person deems necessary or as required by law or by the Underwriters, and any such action previously taken is hereby ratified, confirmed and approved.

8. The Board hereby approves (i) the fee of PFM Financial Advisors LLC (the "Municipal Advisor") as the municipal advisor to the Authority in connection with the sale and issuance of the 2024-1 Bonds, which fee shall not exceed $85,000, (ii) the fee of Norton Rose Fulbright US LLP as Bond Counsel and Disclosure Counsel to the Authority in connection with the sale and issuance of the 2024-1 Bonds, which fee shall not exceed $190,000, and (iii) the fee of Nixon Peabody LLP as Special Tax Counsel to the Authority, which fee shall not exceed $60,000.

9. U.S. Bank Trust Company, National Association is hereby appointed as the Trustee and Paying Agent under the Indenture. Each of the Authorized Representatives is hereby authorized to appoint from time to time any additional fiduciaries, depositaries or agents in connection with the 2024-1 Bonds or any portion thereof and to execute and deliver any and all agreements, documents and instruments necessary or advisable in connection with such appointment of U.S. Bank Trust Company, National Association and with any other such appointment.

10. The following are hereby designated as Renewal Transmission Project Agreements under the Indenture and the Renewal Southern Transmission System Agreement (as defined in the Indenture): (a) the Original Indenture, as heretofore supplemental and amended; (b) the Third Supplemental Indenture; (c) any resolution of this Board of Directors as to the provision of certain continuing disclosure information with respect to the 2024-1 Bonds; and (d) any municipal bond

insurance policy or Debt Service Reserve Account Policy relating to the 2024-1 Bonds obtained in accordance with Section 6 of this Resolution.

11. The Executive Director of the Authority, in addition to the other offices or positions with the Authority he already holds, is hereby appointed an Authorized Authority Representative under the Indenture for the purpose of taking any and all required or permitted actions in connection with the issuance and delivery of the 2024-1 Bonds.

12. Each of the President, any Vice President, Executive Director, Chief Financial and Administrative Officer, Secretary and any Assistant Secretary and any other officer or official of the Authority is hereby authorized to execute and deliver any and all agreements, amendments, documents and instruments and to do and cause to be done any and all acts and things deemed necessary or advisable for carrying out the transactions contemplated by this Resolution and to do and cause to be done any and all acts and things required to perform the Authority's obligations under the Third Supplemental Indenture, the Indenture and any other agreements, amendments, documents and instruments relating to the 2024-1 Bonds (including, but not limited to, (i) executing and delivering, or approving, as applicable, any investment agreement or agreements relating to the investment of 2024-1 Bonds proceeds, (ii) providing for the giving of written directions and notices, and the securing any necessary third party consents or approvals, as required by the Indenture or any other documents relating to the 2024-1 Bonds or the STS Renewal Agreements and (iii) making such changes to the agreements, documents and instruments referred to in this Resolution, and such changes as shall be requested by any rating agency, the Underwriters or any other entity, if such changes are determined by any such officer or official of the Authority to be necessary or advisable, such necessity or advisability to be conclusively evidenced by such officer's or official's execution and delivery thereof). Each reference in this Resolution to the President, Vice President, Executive Director, Chief Financial and Administrative Officer, Secretary, Assistant Secretary or other officer or official shall refer to the person holding such office or position, as applicable, at the time a given action is taken and shall not be limited to the person holding such office or position at the time of the adoption of this Resolution. All actions heretofore taken by the officers, officials, employees and agents of the Authority in furtherance of the transactions contemplated by this Resolution are hereby approved, ratified and confirmed.

13. The Board hereby approves the execution and delivery of all agreements, documents, certificates and instruments referred to herein with electronic signatures as may be permitted under the California Uniform Electronic Transaction Act and digital signatures as may be permitted under Section 16.5 of the California Government Code.

14. In compliance with California Government Code Section 5852.1, the Authority has obtained from the Municipal Advisor the required good faith estimates in connection with the 2024-1 Bonds required by such section, which estimates are disclosed and set forth on Exhibit A attached hereto.

16. The Board finds that this action is statutorily exempt from the requirements of CEQA under Sections 15060(c)(3) and 15601(b)(3) of the State CEQA Guidelines.

/ / /

/ / /

17. This Resolution No. 2024-014 shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority this 18th day of April, 2024.

____

PRESIDENT
Southern California Public
Power Authority

ATTEST:

____

RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

EXHIBIT A

GOOD FAITH ESTIMATES (UNDER SECTION 5852.1 OF THE CALIFORNIA GOVERNMENT CODE)

The good faith estimates set forth herein are provided with respect to the 2024-1 Bonds in compliance with Section 5852.1 of the California Government Code. Such good faith estimates have been provided to the Authority by PFM Financial Advisors LLC, as municipal advisor to the Authority (the "Municipal Advisor").

Principal Amount. The Municipal Advisor has informed the Authority that, based on the Authority's financing plan and current market conditions, its good faith estimate of the aggregate principal amount of the 2024-1 Bonds to be sold is $548,920,000 (the "Estimated Principal Amount").

True Interest Cost of the 2024-1 Bonds. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the 2024-1 Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the initial true interest cost in aggregate of the 2024-1 Bonds, which means the rate necessary to discount the amounts payable on the respective principal and interest payment dates to the purchase price received for the 2024-1 Bonds, is 4.01%. This estimate is based on a finance charge for the 2024-1 Bonds as described below.

Finance Charge for the 2024-1 Bonds. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the 2024-1 Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the finance charge for the 2024-1 Bonds, which means the sum of all fees and charges paid to third parties (or costs associated with the 2024-1 Bonds), is $1,947,049.

Amount of Proceeds to be Received. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the 2024-1 Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the amount of proceeds expected to be received by the Authority for sale of the 2024-1 Bonds, less the finance charge of the 2024-1 Bonds, as estimated above, and any reserves or capitalized interest paid or funded with proceeds of the 2024-1 Bonds, is $519,799,164 .

Total Payment Amount. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the 2024-1 Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the total payment amount, which means the sum total of all payments the Authority will make to pay debt service on the 2024-1 Bonds, plus the finance charge for the 2024-1 Bonds, as described above, not paid with the proceeds of the 2024-1 Bonds, calculated to the final maturity of the 2024-1 Bonds, is $1,101,016,876.

The foregoing estimates constitute good faith estimates only. The actual principal amount of the 2024-1 Bonds issued and sold, the true interest cost thereof, the finance charges thereof, the amount of proceeds received therefrom and total payment amount with respect thereto may differ from such good faith estimates due to (a) the actual date of the sale of the 2024-1 Bonds being different than the date assumed for purposes of such estimates, (b) the actual principal amount of 2024-1 Bonds sold being different from the Estimated Principal Amount, (c) the actual amortization of the 2024-1 Bonds being different than the amortization assumed for purposes of such estimates, (d) the actual market interest rates at the time of sale of the 2024-1 Bonds being different than those estimated for purposes of such estimates, (e) other market conditions or (f) alterations in the Authority's financing plan, or a combination of such factors. The actual date of sale of the 2024-1 Bonds and the actual principal amount of 2024-1 Bonds sold will be determined by the Authority based on market and other factors. The actual interest rates borne by the 2024-1 Bonds will depend on, among other things, market interest rates at the time of sale thereof. The actual amortization of the 2024-1 Bonds will also depend, in part, on market interest rates at the time of sale thereof. Market interest rates are affected by economic and other factors beyond the control of the Authority.

[Project Vote: Burbank, Glendale and LADWP]

RESOLUTION NO. 2024-015

RESOLUTION AS TO THE PROVISION OF CERTAIN CONTINUING DISCLOSURE INFORMATION WITH RESPECT TO SOUTHERN TRANSMISSION SYSTEM RENEWAL PROJECT, REVENUE BONDS, 2024-1

WHEREAS, the Board of Directors of the Southern California Public Power Authority, a political subdivision of the State of California ("SCPPA"), has authorized the issuance of SCPPA's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "Bonds"), and SCPPA has authorized the execution by SCPPA of an Indenture of Trust, dated as of April 1, 2023, from SCPPA to U.S. Bank Trust Company, National Association, as trustee (as supplemented and amended, the "Indenture"), relating to the Bonds; and

WHEREAS, the Board of Directors of SCPPA hereby finds and determines that it is necessary, in connection with the authorization and sale of the Bonds, that SCPPA adopt this resolution in order to assist the Participating Underwriter (such term, and all other capitalized terms used herein without definition, having the respective meanings assigned thereto in Section 1 hereof) in complying with the Rule;

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of SCPPA as follows:

1. Definitions. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Resolution unless otherwise defined in this Disclosure Resolution, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report provided by SCPPA pursuant to, and as described in, Sections 3 and 4 of this Disclosure Resolution.

"Audited Financial Statements" shall mean:

(i) with respect to SCPPA, SCPPA's audited financial statements for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time (or such other accounting principles as may be applicable to SCPPA in the future pursuant to applicable law); and

(ii) with respect to LADWP (as defined in Section 2(b) hereof), the audited financial statements of LADWP's Power System for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities, from time to time (or such other accounting principles as may be applicable to LADWP in the future pursuant to applicable law).

"Beneficial Owner" shall mean any person holding a beneficial ownership interest in Bonds through nominees or depositories (including any person holding such interest through the book-entry only system of The Depository Trust Company), together with any other person who is intended to be a beneficiary of this Disclosure Resolution under the Rule.

"Disclosure Resolution" shall mean this resolution, as the same may be amended or supplemented from time to time in accordance with the provisions hereof.

"Dissemination Agent" shall mean any person or entity appointed by SCPPA and which has entered into a written agreement with SCPPA pursuant to which such person or entity agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

"Final Official Statement" shall mean the Official Statement of SCPPA relating to the Bonds, as amended, supplemented or updated.

"Financial Obligation" shall have the meaning ascribed to it in the Rule, any other applicable federal securities laws and guidance provided by the SEC in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), any further amendments or written guidance provided by the SEC or its staff with respect to the amendments to the Rule effected by the 2018 Release.

"Listed Events" shall mean any of the events listed in Section 5(a) of this Disclosure Resolution.

"MSRB" shall mean the Municipal Securities Rulemaking Board established pursuant to Section 15B(b)(1) of the Securities Exchange Act of 1934 or any other entity designated or authorized by the SEC to receive reports pursuant to the Rule. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the Electronic Municipal Market Access (EMMA) website of the MSRB, currently located at *http://emma.msrb.org*.

"Participating Underwriter" shall mean any of the original underwriters of the Bonds (or the underwriter, if there is only one original underwriter) required to comply with the Rule in connection with the offering of the Bonds.

"Rule" shall mean Rule 15c2-12 adopted by the SEC under the Securities Exchange Act of 1934, as amended from time to time, together with all interpretive guidances or other official interpretations or explanations thereof that are promulgated by the SEC.

"SEC" shall mean the United States Securities and Exchange Commission.

2. Purpose of this Disclosure Resolution; Obligated Persons; Disclosure Resolution to Constitute a Contract.

(a) This Disclosure Resolution is adopted by SCPPA for the benefit of the Owners and Beneficial Owners of the Bonds and in order to assist the Participating Underwriter in complying with the Rule.

(b) Each of SCPPA and the Department of Water and Power of The City of Los Angeles ("LADWP") is hereby determined by SCPPA to be an "obligated person" within the meaning of the Rule (and are the only "obligated persons" within the meaning of the Rule for whom financial information or operating data are presented in the Final Official Statement). Each such person shall only be an "obligated person" if and for so long as such person is an "obligated person" within the meaning of the Rule.

(c) In consideration of the purchase and acceptance of any and all of the Bonds by those who shall hold the same or shall own beneficial ownership interests therein from time to time, this Disclosure Resolution shall be deemed to be and shall constitute a contract between SCPPA and the Owners and Beneficial Owners from time to time of the Bonds, and the covenants and agreements herein set forth to be performed on behalf of SCPPA shall be for the benefit of the Owners and Beneficial Owners of any and all of the Bonds.

3. Provision of Annual Reports.

(a) SCPPA hereby covenants and agrees that it shall, or shall cause the Dissemination Agent to, not later than six months after the end of each fiscal year of SCPPA (presently, by each December 31, each such date being referred to herein as a "Final Submission Date"), commencing with the report for fiscal year 2023-24, provide to the MSRB an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Resolution. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Resolution; provided that any Audited Financial Statements may be submitted separately from the balance of the Annual Report and later than the Final Submission Date if they are not available by that date. If the fiscal year for SCPPA or LADWP changes, SCPPA shall give notice of such change in the same manner as for a Listed Event under Section 5(c).

(b) Not later than ten (10) business days prior to each Final Submission Date (each such date being referred to herein as a "Preliminary Submission Date"), SCPPA shall provide the Annual Report to the Dissemination Agent, if any. If by a Preliminary Submission Date, the Dissemination Agent, if any, has not received a copy of the Annual Report, the Dissemination Agent shall contact SCPPA to determine if SCPPA is in compliance with subsection (a).

(c) If SCPPA or the Dissemination Agent (if any), as the case may be, has not provided any Annual Report to the MSRB by a Final Submission Date, SCPPA or the Dissemination Agent, as applicable, shall provide a notice to the MSRB in substantially the form attached hereto as Exhibit A.

(d) SCPPA (or, in the event that SCPPA shall appoint a Dissemination Agent hereunder, the Dissemination Agent) shall provide the Annual Report to the MSRB on or before the Final Submission Date. In addition, if SCPPA shall have appointed a Dissemination Agent hereunder, the Dissemination Agent shall file a report with SCPPA certifying that the Annual Report has been provided to the MSRB pursuant to this Disclosure Resolution and stating the date it was provided.

(e) Any Annual Report must be submitted in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

4. Content of Annual Reports. SCPPA's Annual Report shall contain or include by reference the following:

(a) If available at the time of filing of the Annual Report as provided herein, the Audited Financial Statements of SCPPA and LADWP for the most recently ended fiscal year. If any Audited Financial Statements are not available by the Final Submission Date, the Annual Report shall contain unaudited financial statements for SCPPA or LADWP, as applicable, in a format similar to the audited financial statements most recently prepared for such obligated person, and such Audited Financial Statements shall be filed in the same manner as the Annual Report when and if they become available.

(b) Updated versions of the type of information contained in the Final Official Statement relating to the following:

1. operation and maintenance and operating statistics of the Southern Transmission System Renewal Project as set forth under the section entitled "SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT" and under the subsection entitled "IPP OPERATIONS – Management and Operation of IPP - Operating Statistics" in Appendix B; and

2. the debt service requirements contained in Appendix G to the Final Official Statement.

(c) Updated versions of the type of information for LADWP contained in Appendix A to the Final Official Statement relating to the following:

1. the description of operations and the summary of operating results of LADWP's Power System; and

2. the summary of financial results of LADWP's Power System.

(d) If known to SCPPA, the name, address and telephone number of a place where current information regarding any bond insurer with respect to the Bonds (the "Bond Insurer") may be obtained.

Any or all of the items listed above may be included by specific reference to other documents, including Annual Reports of SCPPA or LADWP or official statements relating to debt or other securities issues of SCPPA or LADWP or other entities, which have been submitted to the MSRB. If the document included by reference is a final official statement (as defined in the Rule), it must be available from the MSRB. SCPPA shall clearly identify each such other document so included by reference.

5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, SCPPA hereby covenants and agrees that it shall give, or cause to be given, notice of the occurrence of any of the following events with respect to the Bonds:

1. principal or interest payment delinquencies;

2. non-payment related defaults, if material;

3. modifications to the rights of the Bondholders, if material;

4. optional, contingent or unscheduled calls, if any of the preceding are material, and tender offers;

5. defeasances;

6. rating changes;

7. adverse tax opinions or the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of a Bond or other material events affecting the tax status of the Bonds;

8. unscheduled draws on debt service reserves reflecting financial difficulties;

9. unscheduled draws on credit enhancements reflecting financial difficulties;

10. substitution of credit or liquidity providers or their failure to perform;

11. release, substitution or sale of property securing repayment of the Bonds, if material;

12. bankruptcy, insolvency, receivership or similar proceedings described below of SCPPA or LADWP;

13. appointment of a successor or additional trustee or the change of name of a trustee, if material;

14. the consummation of a merger, consolidation, or acquisition involving SCPPA or LADWP or the sale of all or substantially all of the assets of the Southern Transmission System Renewal Project other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

15. incurrence of a Financial Obligation of SCPPA or LADWP, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of SCPPA or LADWP, any of which affects Holders of the Bonds, if material; or

16. default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of SCPPA or LADWP, any of which reflect financial difficulties.

(b) An event described in item 12 above of Section 5(a) is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent, or similar officer for SCPPA or LADWP in a proceeding under the United States Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of said party, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement, or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of said party.

(c) SCPPA intends to comply with the provisions hereof for the Listed Events described in items (15) and (16) of Section 5(a) above, and the definition of the "Financial Obligation" in Section 2, with reference to the Rule, any other applicable federal securities laws and guidance provided by the SEC in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), any further amendments or written guidance provided by the SEC or its staff with respect to the amendments to the Rule effected by the 2018 Release.

(d) SCPPA shall provide notice of an occurrence of a Listed Event to the MSRB in a timely manner but not more than ten (10) business days after the occurrence of the event. Any notice of Listed Event(s) must be submitted to the MSRB in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

6. Management's Discussion of Items Disclosed in Annual Reports or as Significant Events. If an item required to be disclosed in SCPPA's Annual Report under Section 4, or as a Listed Event under Section 5, would be misleading without discussion, SCPPA additionally covenants and agrees that it shall

provide a statement clarifying the disclosure in order that the statement made will not be misleading in the light of the circumstances under which it is made.

7. Termination of Reporting Obligations. SCPPA's obligations under this Disclosure Resolution shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Bonds. In addition, in the event that the Rule shall be amended, modified or repealed such that compliance by SCPPA with its obligations under this Disclosure Resolution no longer shall be required in any or all respects, then SCPPA's obligations under this Disclosure Resolution shall terminate to a like extent. If either such termination occurs prior to the final maturity of the Bonds, SCPPA shall give notice of such termination in the same manner as for a Listed Event under Section 5(d).

8. Dissemination Agent. SCPPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Resolution, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent.

9. Amendment; Waiver.

(a) Notwithstanding any other provision of this Disclosure Resolution, SCPPA may, by resolution hereafter adopted, amend this Disclosure Resolution, and any provision of this Disclosure Resolution may be waived, provided that, in the opinion of nationally-recognized bond counsel, such amendment or waiver is permitted by the Rule.

(b) The Annual Report containing any modified operating data or financial information as a result of an amendment shall explain, to the extent required by the Rule, in narrative form, the reasons for the amendment and the impact of the change in the type of operating data or financial information being provided. If a change in accounting principles is included in any such modification, such Annual Report shall present, to the extent required by the Rule, a comparison between the financial statements or information prepared on the basis of the modified accounting principles and those prepared on the basis of the former accounting principles.

10. Additional Information. Nothing in this Disclosure Resolution shall be deemed to prevent SCPPA from disseminating, or require SCPPA to disseminate, any other information, using the means of dissemination set forth in this Disclosure Resolution or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Resolution. If SCPPA chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Resolution, SCPPA shall have no obligation under this Disclosure Resolution to update such information or include it in any future Annual Report, notice of occurrence of a Listed Event or other materials disseminated hereunder.

11. Default.

(a) In the event of a failure of SCPPA to comply with any provision of this Disclosure Resolution, any Owner or Beneficial Owner of any Outstanding Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, for the equal benefit and protection of all Owners or Beneficial Owners similarly situated, to cause SCPPA to comply with its obligations under this Disclosure Resolution.

(b) Notwithstanding the foregoing, no Owner or Beneficial Owner of the Bonds shall have the right to challenge the content or adequacy of the information provided pursuant to Sections 3, 4 or 5 of this Disclosure Resolution by mandamus, specific performance or other equitable proceedings unless

Owners or Beneficial Owners of Bonds representing at least 25% in aggregate principal amount of the Outstanding affected Bonds shall join in such proceedings.

(c) A default under this Disclosure Resolution shall not be deemed an Event of Default under the Indenture, and the sole remedies under this Disclosure Resolution in the event of any failure of SCPPA to comply with this Disclosure Resolution shall be those described in subsection (a) above.

(d) Under no circumstances shall any person or entity be entitled to recover monetary damages hereunder in the event of any failure of SCPPA to comply with this Disclosure Resolution.

12. Duties, Immunities and Liabilities of Dissemination Agent. Any Dissemination Agent appointed hereunder shall have only such duties as are specifically set forth in this Disclosure Resolution and shall have such rights, immunities and liabilities as shall be set forth in the written agreement between SCPPA and such Dissemination Agent pursuant to which such Dissemination Agent agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

13. Beneficiaries. This Disclosure Resolution shall inure solely to the benefit of SCPPA, the Dissemination Agent, if any, and the Owners and Beneficial Owners from time to time of the Bonds, and, subject to Section 2(a) hereof, shall create no rights in any other person or entity.

14. Governing Law. This Disclosure Resolution shall be deemed to be a contract made under the Rule and the laws of the State of California, and for all purposes shall be construed and interpreted in accordance with, and its validity governed by, the Rule and the laws of the State of California, without regard to principles of conflicts of law.

15. Effective Date. This Disclosure Resolution shall become effective upon the date of authentication and delivery of the Bonds.

THE FOREGOING RESOLUTION is approved and adopted by SCPPA this 18th day of April, 2024.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

____
PRESIDENT
Southern California Public
Power Authority

ATTEST:

____
RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Southern California Public Power Authority
Name of Bond Issue:	$__________ Southern Transmission System Renewal Project, Revenue Bonds, 2024-1,
Date of Issuance:	___________ __, 2024

NOTICE IS HEREBY GIVEN that Southern California Public Power Authority ("SCPPA") has not provided an Annual Report with respect to the above-named Bonds as required by Section 3(a) of Resolution No. 2024-____, adopted by the Board of Directors of SCPPA on April 18, 2024, relating to the above-named Bonds. SCPPA has advised the undersigned that SCPPA anticipates that the Annual Report will be filed by __________________.

Dated: _______________

[SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY]
[__________________, as Dissemination Agent on behalf of Southern California Public Power Authority]

[cc: Southern California Public Power Authority]

DRAFT OF
02/__/24

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

To

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION,
as Trustee

____

THIRD SUPPLEMENTAL INDENTURE OF TRUST

____

Dated as of _____ 1, 2024

$___________
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

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THIRD SUPPLEMENTAL INDENTURE OF TRUST

THIS THIRD SUPPLEMENTAL INDENTURE OF TRUST (the "Third Supplemental Indenture") dated as of _____ 1, 2024 from Southern California Public Power Authority, established under the laws of the State of California (the "Authority"), to U.S. Bank Trust Company, National Association, a national banking association, as trustee (the "Trustee");

W I T N E S S E T H :

WHEREAS, the Authority has entered into an Indenture of Trust, dated as of April 1, 2023 (the "Original Indenture" and, as supplemented and amended, including as supplemented by this Third Supplemental Indenture, the "Indenture"), from the Authority to the Trustee to provide for the securing of Bonds; and

WHEREAS, the Authority has heretofore entered into a First Supplemental Indenture of Trust, dated as of April 1, 2023 (the "First Supplemental Indenture"), from the Authority to the Trustee, providing for the issuance of its Southern Transmission System Renewal Project, Revenue Bonds, 2023-1 (the "2023-1 Bonds") in the aggregate principal amount of $254,695,000, in order to finance a portion of the Cost of Acquisition of Capacity; and

WHEREAS, the Authority has heretofore entered into a Second Supplemental Indenture of Trust, dated as of May 1, 2023 (the "Second Supplemental Indenture"), from the Authority to the Trustee, providing for the issuance of its Southern Transmission System Renewal Project, Revenue Bonds, 2023-1A (the "2023-1A Bonds") in the aggregate principal amount of $431,495,000, in order to finance a portion of the Cost of Acquisition of Capacity; and

WHEREAS, the Authority desires to issue its Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "2024-1 Bonds") in the aggregate principal amount of $____________, in order to finance a portion of the Cost of Acquisition of Capacity; and

WHEREAS, the 2024-1 Bonds will be issued and secured under the Indenture; and

WHEREAS, all acts and things have been done and performed that are necessary to make the 2024-1 Bonds, when executed and issued by the Authority, authenticated by the Trustee and delivered, the valid and binding legal obligations of the Authority in accordance with their terms and to make this Third Supplemental Indenture a valid and binding agreement for the security of the 2024-1 Bonds authenticated and delivered under the Indenture;

NOW, THEREFORE, THIS THIRD SUPPLEMENTAL INDENTURE WITNESSETH:

That, in consideration of the premises, the acceptance by the Trustee of the trusts hereby created and originally created by the Original Indenture, the mutual covenants herein contained and the purchase and acceptance of the 2024-1 Bonds issued hereunder by the Owners thereof, and for other valuable consideration, the receipt of which is hereby acknowledged, and in order to secure the payment of the principal or Redemption Price (if any) of, and interest on, the 2024-1 Bonds issued hereunder according to their tenor and effect, and the performance and observance by the Authority of all the covenants and conditions contained herein and in the Indenture on its part to be performed, it is agreed by and between the Authority and the Trustee as follows:

ARTICLE I

AUTHORITY AND DEFINITIONS

101. Authority for this Third Supplemental Indenture. This Third Supplemental Indenture is a Supplemental Indenture executed pursuant to the provisions of the Act and in accordance with Article II and Article X of the Original Indenture.

102. Definitions.

(1) Except as provided by this Third Supplemental Indenture, all terms that are defined in the Original Indenture shall have the same meanings in this Third Supplemental Indenture as such terms are given in the Original Indenture.

(2) In this Third Supplemental Indenture:

Interest Payment Date shall mean, with respect to the 2024-1 Bonds, January 1 and July 1 of each year, commencing [July] 1, 2024, as specified in Section 203 of this Third Supplemental Indenture.

2024-1 Bonds shall mean the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, authorized by Article II of this Third Supplemental Indenture.

2024-1 Capitalized Interest Account shall mean the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Capitalized Interest Account established pursuant to Section 303 of this Third Supplemental Indenture.

2024-1 Costs of Issuance Subaccount shall mean the special subaccount in the 2024-1 Project Account designated as the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Costs of Issuance Subaccount established pursuant to Section 301 of this Third Supplemental Indenture.

2024-1 Debt Service Account shall mean the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Debt Service Account established pursuant to Section 302 of this Third Supplemental Indenture.

2024-1 Debt Service Reserve Account shall mean the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Debt Service Reserve Account established pursuant to Section 304 of this Third Supplemental Indenture.

2024-1 Debt Service Reserve Account Policy shall mean a surety bond, insurance policy, line of credit, letter of credit or similar instrument issued to the Trustee by an entity licensed to issue a surety bond, insurance policy, line of credit, letter of credit or similar instrument guaranteeing the timely payment of debt service on the 2024-1 Bonds (such entity, a "municipal bond insurer"), which municipal bond insurer, at the time any such surety bond, insurance policy, line of credit, letter of credit or similar instrument is issued, shall have its claims paying ability rated in not lower than the second highest rating category (without regard to any gradations within any such category) by at least two nationally-recognized credit rating agencies.

2024-1 Debt Service Reserve Requirement shall mean $0.

2024-1 Parity Swap shall mean any Parity Swap hereafter entered into by the Authority which shall be designated to the Trustee by an Authorized Authority Representative as a 2024-1 Parity Swap (whether or not such Parity Swap shall relate to any particular Series of Bonds as provided in such Parity Swap).

2024-1 Parity Swap Provider shall mean the provider of any 2024-1 Parity Swap.

2024-1 Project Account shall mean the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Project Account established pursuant to Section 301 of this Third Supplemental Indenture.

ARTICLE II

AUTHORIZATION OF 2024-1 BONDS

201. Principal Amount, Designation and Series. Pursuant to the provisions of the Indenture, a Series of Bonds entitled to the benefit, protection and security of such provisions is hereby authorized in the aggregate principal amount of $___________. Such Bonds shall be designated as, and shall be distinguished from the Bonds of all other Series by the title, "Southern Transmission System Renewal Project, Revenue Bonds, 2024-1."

202. Purposes.

(1) The 2024-1 Bonds are issued for the purposes of financing a portion of the Cost of Acquisition of Capacity.

(2) The purposes set forth in paragraph (1) of this Section 202 shall constitute purposes described in Section 203 of the Original Indenture.

Pursuant to Section 202 of the Original Indenture, it is hereby determined that the 2024-1 Bonds shall not be Participating Bonds pursuant to the Original Indenture and that a Series Debt Service Reserve Account shall instead be established and maintained for the 2024-1 Bonds. The Debt Service Reserve Requirement for the 2024-1 Bonds is hereby determined to be an amount equal to the 2024-1 Debt Service Reserve Requirement (i.e., $0).

203. Date, Maturities and Interest. The 2024-1 Bonds shall be dated their date of delivery. Interest on the 2024-1 Bonds shall be payable on [July 1, 2023], and semiannually thereafter on each January 1 and July 1, which dates are hereby specified as the Interest Payment Dates for the 2024-1 Bonds pursuant to the provisions of the Original Indenture. The 2024-1 Bonds shall bear interest from the Interest Payment Date next preceding the date of authentication thereof unless such 2024-1 Bonds are authenticated on an Interest Payment Date, in which event from such Interest Payment Date; provided, however, that if the date of authentication shall be prior to the first Interest Payment Date for the 2024-1 Bonds, such 2024-1 Bonds shall bear interest from their date of delivery; and provided, further, that if, on the date of authentication thereof, interest on the 2024-1 Bonds shall be in default as shown by the records of the Trustee, such 2024-1 Bonds shall bear interest from the Interest Payment Date to which interest has been paid or duly provided for in full. Interest on the 2024-1 Bonds shall be calculated on the basis of a 360-day year comprised of twelve 30-day months.

The 2024-1 Bonds shall mature on July 1 in the years and in the principal amounts, and shall bear interest payable semiannually on each Interest Payment Date therefor, at the respective interest rates and yields per annum, shown below:

Year	Principal Amount	Interest Rate	Yield

204. Registered Form, Denomination, Numbers and Letters. The 2024-1 Bonds shall be issued in fully registered form in the denominations of $5,000 or any integral multiple of $5,000. The 2024-1 Bonds shall be registered in book-entry format as provided in Section 309 of the Original Indenture. The 2024-1 Bonds initially issued shall be numbered in a manner determined by the Trustee so as to be distinguished from every other such 2024-1 Bond, with each such number designation preceded by the letter "R."

205. Place of Payment and Paying Agents. Subject to Section 309 of the Original Indenture, the principal and Redemption Price (if any) of the 2024-1 Bonds shall be payable upon presentation and surrender at the corporate trust office of U.S. Bank Trust Company, National Association, St. Paul, Minnesota, or such other office designated by the Trustee, and U.S. Bank Trust Company, National Association is hereby appointed as Paying Agent for the 2024-1 Bonds. The principal and Redemption Price (if any) of the 2024-1 Bonds shall also be payable at any other place that may be provided for such payment by the appointment of any other Paying Agent or Paying Agents as permitted by the Indenture. Interest on the 2024-1 Bonds shall be payable by check of the Trustee mailed by first-class mail to the registered owners shown on the registration books of the Authority kept by the Bond Registrar as of the close of business on the record date (established as provided below) immediately preceding each Interest Payment Date, except that in the case of an Owner of $1,000,000 or more in aggregate principal amount of 2024-1 Bonds, upon written request of such Owner to the Trustee received at least ten (10) days prior to the applicable record date, specifying the account or accounts to which such payment shall be made (which request shall remain in effect until revoked or reversed by such Owner in a subsequent writing delivered to the Trustee), such interest shall be paid in immediately available funds by wire transfer to such account or accounts on each such following Interest Payment Date. As provided in subsection 4 of Section 301 of the Original Indenture, the record dates for the payment of interest on the 2024-1 Bonds are hereby established as the fifteenth (15th) day of the calendar month immediately preceding each Interest Payment Date.

206. Redemption Prices and Terms.

(1) Sinking Fund Redemption. The 2024-1 Bonds due July 1, 2048 and July 1, 2053 shall be subject to redemption prior to maturity as provided in Article IV of the Original Indenture by operation of the Debt Service Fund to satisfy Sinking Fund Installments, on and after July 1, ____ and July 1, ____, respectively, at a Redemption Price equal to the principal amount of the 2024-1 Bonds to be so redeemed (together with accrued interest thereon), without premium.

(2) Optional Redemption. The 2024-1 Bonds maturing on or after July 1, [2035] shall be subject to redemption prior to maturity, at the option of the Authority, from any source of available funds, in whole or in part (and, if in part, from such maturities as the Authority shall direct), on any date on or after July 1, [2034], at a Redemption Price equal to the principal amount of the 2024-1 Bonds, or portions thereof, to be redeemed, without premium, in each case together with accrued interest to the redemption date.

(3) Selection of 2024-1 Bonds for Redemption. Whenever by the terms of the Indenture, 2024-1 Bonds are to be redeemed at the direction of the Authority, the Authority shall select the maturity or maturities of the 2024-1 Bonds to be redeemed. If less than all of the 2024-1 Bonds of a maturity are called for prior redemption, the particular 2024-1 Bonds or portions of such maturity to be redeemed shall be selected by lot, subject to the authorized denominations applicable to the 2024-1 Bonds, and otherwise as provided in Section 404 of the Original Indenture. The Trustee shall promptly notify the Authority in writing of the 2024-1 Bonds so selected for redemption.

207. Sinking Fund Installments. Sinking Fund Installments are hereby established for the 2024-1 Bonds maturing on July 1, ______ and July 1, ______. Such Sinking Fund Installments shall be due on July 1 of each of the years set forth in the following tables in the redemption amounts set forth opposite such years in said tables:

2024-1 Bonds Due July 1, ____

July 1	Redemption Amount

2024-1 Bonds Due July 1, ____

July 1	Redemption Amount

In connection with any optional redemption pursuant to subsection (2) of Section 206 hereof of any 2024-1 Bonds that are term 2024-1 Bonds subject to mandatory sinking fund redemption, the principal amount of such 2024-1 Bonds being redeemed shall be allocated against the scheduled sinking fund redemption amounts in such manner as the Authority may direct and the scheduled sinking fund installments payable after such redemption shall be modified as to such term 2024-1 Bonds. In such event, the Authority shall provide to the Trustee a revised schedule of Sinking Fund Installments for purposes of this Section 207.

208. Application of Proceeds of 2024-1 Bonds; Deposit of Moneys. In accordance with subsection 2 of Section 203 of the Original Indenture, the proceeds of the 2024-1 Bonds, being $____________ (representing the $____________ aggregate principal amount of the 2024-1 Bonds plus $_________ original issue premium and less $________ underwriters' discount), shall be applied simultaneously with the delivery of the 2024-1 Bonds, as follows:

(i) There shall be deposited in the 2024-1 Capitalized Interest Account in the amount of $__________; and

(ii) The remaining balance of proceeds of the 2024-1 Bonds (i.e., $____________) shall be deposited in the Construction Fund, of which $___________ shall be deposited in the 2024-1 Project Account to be used to pay certain Cost of Acquisition of Capacity and $_________ shall be deposited in the 2024-1 Costs of Issuance Subaccount to be used to pay costs of issuance relating to the 2024-1 Bonds.

209. Investment Income. Interest and other investment income (net of that which (i) represents a return of accrued interest paid in connection with the purchase of any investment and (ii) is required to offset the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in the Funds and Accounts (other than any Rebate Fund) established under the Indenture, to the extent resulting in a balance that is in excess of any requirement for such Fund or Account, shall be paid into the Revenue Fund.

210. Form of 2024-1 Bonds; Trustee's Certificate of Authentication; Execution. Subject to the provisions of the Indenture, the form of the 2024-1 Bonds and the Trustee's certificate of authentication shall be of substantially the tenor set forth in Article XIII of the Original Indenture. The 2024-1 Bonds may be executed by manual or facsimile signature of the President or a Vice President of the Authority and the seal may be attested by the manual or facsimile signature of the Secretary or an Assistant Secretary of the Authority.

ARTICLE III

ESTABLISHMENT OF 2024-1 PROJECT ACCOUNT, 2024-1 DEBT SERVICE ACCOUNT AND 2024-1 DEBT SERVICE RESERVE ACCOUNT

301. Establishment and Application of 2024-1 Project Account.

(1) The Authority shall establish and the Trustee shall maintain and hold in trust in the Construction Fund a separate account designated as the "Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Project Account," with a separate subaccount therein designated as the "Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Costs of Issuance Subaccount." Amounts in the 2024-1 Project Account and 2024-1 Costs of Issuance Subaccount shall be applied as set forth in Section 503 of the Original Indenture and in this Section 301.

(2) Upon receipt of any requisition signed by an Authorized Authority Representative for payment or reimbursement from the Construction Fund pursuant to Section 503 of the Original Indenture, the Trustee shall, unless instructed by the Authority in such requisition that such payment is to be made from another project account established pursuant to a Supplemental Indenture entered into subsequent to this Third Supplemental Indenture, (i) to the extent such requisition is for the payment of costs of issuance of the 2024-1 Bonds, pay such requisitioned amounts out of the 2024-1 Costs of Issuance Subaccount, and (ii) to the extent that such requisition is for the payment of other items of the Cost of Acquisition of Capacity, pay such requisitioned amounts out of the 2024-1 Project Account. If any amount shall remain in the 2024-1 Costs of Issuance Subaccount after all costs of issuance of the 2024-1 Bonds have been paid, as stated in a certificate of an Authorized Authority Representative, such remainder shall be transferred to the 2024-1 Debt Service Account (with such transferred amount to be used to pay interest on the 2024-1 Bonds), or if no such certificate is received, then 180 days after the date of issuance of the 2024-1 Bonds, the Trustee shall make such transfer and the Trustee shall close the 2024-1 Costs of Issuance Subaccount.

302. Establishment and Application of 2024-1 Debt Service Account.

(1) The Authority shall establish and the Trustee shall maintain and hold in trust in the Debt Service Fund a separate account designated as the "Southern Transmission System

Renewal Project, Revenue Bonds, 2024-1, Debt Service Account." Amounts in the 2024-1 Debt Service Account shall be applied as set forth in this Section 302.

(2) The Trustee shall pay out of the 2024-1 Debt Service Account subject to subsections (3) and (4) of this Section 302, without preference or priority of one transfer over the others (a) to the Paying Agents, if any, (i) on or before each January 1 and July 1 the amount required for the interest payable on such date, (ii) on or before each Principal Installment due date, the amount required for the Principal Installment payable on such due date, and (iii) on or before any redemption date for 2024-1 Bonds, the amount required for the payment of the Redemption Price thereof and interest on the 2024-1 Bonds then to be redeemed and (b) to the 2024-1 Parity Swap Providers, if any, any regularly-scheduled amounts due and payable by the Authority under any 2024-1 Parity Swap on the due date therefor. Amounts so paid to the Paying Agents with respect to the 2024-1 Bonds shall be applied by any such Paying Agents on the due dates thereof. The Trustee shall also pay out of the 2024-1 Debt Service Account the accrued interest included in the purchase price of any 2024-1 Bonds purchased for retirement. Notwithstanding anything to the contrary in this Third Supplemental Indenture or the Original Indenture, any termination payments payable by the Authority under any 2024-1 Parity Swap shall be payable on a basis subordinate and junior to the payments due to 2024-1 Parity Swap Providers described in clause (b) of this subsection (2).

(3) Except as provided in subsection (2) of this Section 302, all amounts held at any time in the 2024-1 Debt Service Account shall be held until applied on a parity basis for the ratable security and payment of (i) Accrued Debt Service on the 2024-1 Bonds and (ii) amounts due and payable by the Authority under the 2024-1 Parity Swaps, if any, at any time in proportion to the amounts accrued or due and payable, as applicable.

(4) In the event of the refunding (or other defeasance) of any 2024-1 Bonds, the Trustee shall, upon the direction of an Authorized Authority Representative acting with the advice of Bond Counsel, withdraw from the 2024-1 Debt Service Account amounts accumulated therein with respect to Debt Service on the 2024-1 Bonds being refunded (or otherwise defeased) and, unless otherwise instructed in writing for an alternative use of such amounts, deposit such amounts with itself as escrow agent to be held for the payment of the principal or Redemption Price, if applicable, of, and interest on the 2024-1 Bonds being refunded (or otherwise defeased); provided that such withdrawal shall not be made unless (a) immediately thereafter the 2024-1 Bonds being refunded (or otherwise defeased) shall be deemed to have been paid pursuant to subsection 2 of Section 1201 of the Original Indenture, and (b) the amount remaining in the 2024-1 Debt Service Account after such withdrawal shall not be less than the amount required to be held therein pursuant to subsection 1 of Section 506 of the Original Indenture.

303. Establishment and Application of 2024-1 Capitalized Interest Account.

(1) The Authority shall establish and the Trustee shall maintain and hold in trust in the Debt Service Fund a separate account designated as the "Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Capitalized Interest Account." The 2024-1 Capitalized Interest Account shall be initially funded upon the issuance and delivery of the 2024-1 Bonds, pursuant to Section 208 hereof. Amounts in the 2024-1 Capitalized Interest Account shall be invested in Investment Securities consisting of [U.S. Treasury Securities—State and Local

Government Series] as set forth in Schedule I hereto and shall be applied as set forth in this Section 303. Interest and other investment income earned on investments in the 2024-1 Capitalized Interest Account shall remain therein, to be applied as set forth in this Section 303.

(2) The Trustee shall pay out of the 2024-1 Capitalized Interest Account to the Paying Agents, if any, on or before each January 1 and July 1, from ____________ to ____________, inclusive, from the interest and maturing principal of the investments therein, together with any uninvested cash held thereunder, the amounts set forth in the table below. Amounts so paid to the Paying Agents shall be applied by any such Paying Agents to the payment of interest on the 2024-1 Bonds on the due dates thereof.

Date	Amount to be Transferred from 2024-1 Capitalized Interest Account

(3) On or after ____________, the Trustee shall transfer any amounts remaining in the 2024-1 Capitalized Interest Account to the Rebate Fund or the 2024-1 Project Account, as instructed by an Authorized Authority Representative.

304. Establishment, Pledge, Funding and Application of 2024-1 Debt Service Reserve Account.

(1) The Authority shall establish and the Trustee shall maintain and hold in trust in the Debt Service Fund a separate account designated as the "Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Debt Service Reserve Account." The 2024-1 Debt Service Reserve Account shall not be initially funded upon the issuance and delivery of the 2024-1 Bonds. At the sole discretion of the Board of Directors, the 2024-1 Debt Service Reserve Account may thereafter be funded from time to time or at any time at such level as determined by the Board of Directors. In the event the 2024-1 Debt Service Reserve Account shall at any time be funded pursuant to this subsection (1) of Section 304, such 2024-1 Debt Service Reserve Account.

(2) During any period in which the Authority has determined, in its sole discretion, to fund the 2024-1 Debt Service Reserve Account as provided in subsection (1) of this Section 304, the amount determined by the Authority to be maintained therein shall, during such period, constitute the 2024-1 Debt Service Reserve Requirement for purposes of this Section 304. Except as provided in subsection (5) of this Section 304, the Authority shall at all times maintain an amount equal to the 2024-1 Debt Service Reserve Requirement in the 2024-1 Debt Service

Reserve Account until the 2024-1 Bonds are discharged in accordance with the provisions of the Indenture. In the event of any deficiency in the 2024-1 Debt Service Reserve Account, the Authority shall replenish such deficiency by depositing monthly at least one twelfth (1/12th) of the aggregate amount of each unreplenished prior draw on the 2024-1 Debt Service Reserve Account and the full amount of any deficiency due to any required valuations of the investments in the 2024-1 Debt Service Reserve Account until the balance in the 2024-1 Debt Service Reserve Account is at least equal to the 2024-1 Debt Service Reserve Requirement.

(3) All Investment Securities credited to the 2024-1 Debt Service Reserve Account shall be valued as of July 1 of each year (or the next preceding or succeeding Business Day, as determined by the Authority, if any such July 1 is not a Business Day) at the greater of the cost of such Investment Securities or the amortized value thereof, exclusive of accrued interest.

(4) Notwithstanding anything to the contrary in the Original Indenture or this Third Supplemental Indenture, all amounts in the 2024-1 Debt Service Reserve Account shall be used and withdrawn by the Trustee solely for the purpose of (i) paying principal of and interest on the 2024-1 Bonds in the event moneys in the 2024-1 Debt Service Account are insufficient, or (ii) making the final principal and interest payment on the 2024-1 Bonds.

(5) In the event of the refunding (or other defeasance) of any 2024-1 Bonds, the Trustee, upon the direction of an Authorized Authority Representative acting with the advice of Bond Counsel, shall withdraw from the 2024-1 Debt Service Reserve Account amounts accumulated therein with respect to Debt Service on the 2024-1 Bonds being refunded (or otherwise defeased) and, unless otherwise instructed in writing for an alternative use of such amounts, deposit such amounts with itself as escrow agent to be held for the payment of the principal or Redemption Price, if applicable, of, and interest on the 2024-1 Bonds being refunded (or otherwise defeased); provided that such withdrawal shall not be made unless (a) immediately thereafter the 2024-1 Bonds being refunded (or otherwise defeased) shall be deemed to have been paid pursuant to subsection 2 of Section 1201 of the Original Indenture, and (b) the amount remaining in the 2024-1 Debt Service Reserve Account after such withdrawal shall not be less than the requirement of such Account pursuant to subsection (2) of this Section 304.

(6) Notwithstanding anything herein to the contrary, at the option of the Authority amounts required to be held in the 2024-1 Debt Service Reserve Account may be substituted, in whole or in part, by the deposit with the Trustee of a 2024-1 Debt Service Reserve Account Policy in a stated amount equal to the amounts so substituted and any 2024-1 Debt Service Reserve Account Policy then held in the 2024-1 Debt Service Reserve Account may be replaced at the option of the Authority by cash or by another 2024-1 Debt Service Reserve Account Policy in whole or in part; provided that prior to the substitution or replacement of such 2024-1 Debt Service Reserve Account Policy the credit rating agencies then rating the 2024-1 Bonds shall have been notified by the Authority of such proposed substitution or replacement and the substitution or replacement shall not result, as evidenced by letters from such rating agencies, in a downgrading or withdrawal of any rating of the 2024-1 Bonds then in effect by such rating agencies; and provided further that the Authority shall have first received an Opinion of Bond Counsel to the effect that such substitution or replacement will not adversely affect, if applicable, the exclusion of interest on the 2024-1 Bonds from the gross income of the owners thereof for federal income tax purposes. Any moneys so withdrawn from the 2024-1 Debt Service Reserve Account shall,

with the prior approval of Bond Counsel, be transferred to the General Reserve Fund and used in accordance with the provisions of Section 512 of the Original Indenture or otherwise used in a manner that is consistent with such Opinion of Bond Counsel.

So long as a 2024-1 Debt Reserve Account Policy shall be in full force and effect, any deposits required to be made with respect to the 2024-1 Debt Service Reserve Account pursuant to Section 506 of the Original Indenture shall include any amounts due to the provider of the 2024-1 Debt Service Reserve Account Policy resulting from a draw on the 2024-1 Debt Service Reserve Account Policy (which amounts shall constitute a deficiency or withdrawal from the 2024-1 Debt Service Reserve Account within the meaning of Section 506 of the Original Indenture). Any such amounts shall be paid to the provider of such 2024-1 Debt Service Reserve Account Policy as provided in such 2024-1 Debt Service Reserve Account Policy or any related agreement.

ARTICLE IV

TAX COVENANTS

401. Tax Covenant. The Authority shall not take any action or omit to take any action that, if taken or omitted, respectively, would adversely affect the excludability of interest on any 2024-1 Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes and, furtherance thereof, shall comply with the Tax Certificate as to Arbitrage and the Provisions of Sections 141-150 of the Internal Revenue Code of 1986 executed and delivered by the Authority on the date of delivery of the 2024-1 Bonds, as the same may be supplemented or amended, including any and all exhibits attached thereto.The Authority and the Trustee shall execute such amendments hereof and supplements hereto (and shall comply with the provisions thereof) as are, in the Opinion of Bond Counsel, necessary to preserve such exclusion. The Authority shall comply with this covenant at all times prior to the last maturity of 2024-1 Bonds or, if necessary, until no longer required to to maintain the excludability of interest on any 2024-1 Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes, unless to comply with such covenant, either generally or to the extent stated therein, shall not adversely affect the excludability of interest on any 2024-1 Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes, and thereafter such covenant shall no longer be binding upon the Authority, generally or to such extent as the case may be.

ARTICLE V

MISCELLANEOUS

501. Indenture to Remain in Effect. Except as supplemented by this Third Supplemental Indenture, the Original Indenture shall remain in full force and effect.

502. Counterparts. This Third Supplemental Indenture may be executed in any number of counterparts, each of which, when so executed and delivered, shall be an original; such counterparts shall together constitute but one and the same instrument.

503. Performance of Duties. The Trustee, including in its capacity as Paying Agent hereunder, agrees to perform its duties set forth herein.

504. Severability. If any one or more of the covenants or agreements provided in this Third Supplemental Indenture to be performed on the part of the Authority or the Trustee, including in its capacity as Paying Agent hereunder, should be determined by a court of competent jurisdiction to be contrary to law, such covenants or agreements shall be null and void and shall be deemed separate from the remaining covenants and agreements contained herein and shall in no way affect the validity of the remaining provisions of this Third Supplemental Indenture.

505. Assignment. The rights, obligations and duties of the Trustee set forth herein, including its rights, obligations and duties as Paying Agent, shall not be assigned by the Trustee or any successor thereto without the prior written consent of the Authority.

506. Effective Date. This Third Supplemental Indenture shall become effective at such time as this Third Supplemental Indenture shall be executed and delivered by the Authority and the Trustee.

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IN WITNESS WHEREOF, Southern California Public Power Authority has caused this Third Supplemental Indenture of Trust to be signed in its name and on its behalf by its President (or a Vice President), and its seal to be hereunto affixed and attested by its Secretary (or an Assistant Secretary), thereunto duly authorized, and to evidence its acceptance of the trusts hereby created, the Trustee has caused these presents to be signed in its name and on its behalf by its duly authorized officer.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

[Authority Seal]

By: ______________________________________
President

Attest ________________________________
Assistant Secretary

U.S. BANK TRUST COMPANY,
NATIONAL ASSOCIATION,
as Trustee

By: ______________________________________
Authorized Signatory

SCHEDULE I

U.S. Treasury Securities – State and Local Government Series
Invested in 2024-1 Capitalized Interest Amount

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

$______________
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

PURCHASE CONTRACT

April 25, 2024

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY
1160 Nicole Court
Glendora, California 91740
Attention: Executive Director

Ladies and Gentlemen:

The undersigned, Barclays Capital Inc., as representative (the "Representative") of itself, RBC Capital Markets, LLC, BofA Securities, Inc., Loop Capital Markets LLC, Samuel A. Ramirez & Co., Inc., Siebert Williams Shank & Co., LLC and TD Securities (USA) LLC (the "Underwriters"), offers to enter into the following agreement (this "Purchase Contract") with Southern California Public Power Authority ("SCPPA") which, upon SCPPA's acceptance of this offer, will be binding upon SCPPA and upon the Underwriters. This offer is made subject to SCPPA's written acceptance hereof on or before 5:00 P.M., Los Angeles time, on the date hereof and, if not so accepted, will be subject to withdrawal by the Underwriters upon written notice (by facsimile transmission or otherwise) delivered to SCPPA by the Representative at any time prior to the acceptance hereof by SCPPA. Terms used herein and not defined shall have the respective meanings assigned to them in the Official Statement (as defined in Section 3). The Representative represents that it has been duly authorized by the other Underwriters to act hereunder on their behalf and shall have full authority to take such action as it may deem advisable in respect of all matters pertaining to this Purchase Contract and that the Representative has been duly authorized to execute this Purchase Contract. Any action taken under this Purchase Contract by the Representative will be binding upon all the Underwriters.

1. Purchase and Sale. Upon the terms and conditions and upon the basis of the representations, warranties and agreements set forth herein, the Underwriters hereby agree, jointly and severally, to purchase from SCPPA, and SCPPA hereby agrees to sell and deliver to the Underwriters, $______________ aggregate principal amount of Southern California Public Power Authority, Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "Bonds"). The Bonds shall be dated their date of delivery and shall mature on July 1 of the years and in the principal amounts and bear interest at the rates (payable on January 1 and July 1 in each year, commencing [July] 1, 2024), as set forth on Schedule I hereto and shall subject to redemption prior to their maturity, if applicable, as shown on Schedule II hereto. The purchase price for the Bonds shall be $______________ (representing the $______________ par amount of the Bonds, plus original issue premium of $______________, and less Underwriters' discount of $______________).

2. **The Bonds**. The Bonds shall be issued and secured pursuant to, the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the "Act"), and, as described in, that certain Indenture of Trust, dated as of April 1, 2023 (the "Indenture of Trust"), from SCPPA to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"), as supplemented by a Third Supplemental Indenture of Trust, dated as of [April 1, 2024] relating to the Bonds (the "Third Supplemental Indenture"), from SCPPA to the Trustee (the Indenture of Trust as supplemented being hereinafter referred to as the "Indenture"). The Bonds shall be payable from the Revenues (as defined in the Indenture) and certain other funds, as provided in the Indenture, and shall be as described in the Official Statement. SCPPA shall provide annual updates of certain financial information and operating data contained or incorporated by reference in the Official Statement and notice of certain specified events with respect to the Bonds pursuant to that certain Continuing Disclosure Resolution relating to the Bonds (the "Disclosure Resolution") adopted by SCPPA's Board of Directors on April 18, 2024, to be effective upon the delivery of the Bonds.

The Bonds are being issued to: (i) provide money to fund payments-in-aid of construction made to Intermountain Power Agency, a political subdivision of the State of Utah ("IPA"), for application to a portion of the initial costs of the Southern Transmission System Renewal Project, (ii) fund capitalized interest for the Bonds and (iii) pay costs of issuance relating to the Bonds.

3. **Delivery of Official Statement**. SCPPA has heretofore delivered to the Underwriters a Preliminary Official Statement, dated April 19, 2024, relating to the Bonds (the "Preliminary Official Statement"), that SCPPA has deemed final as of its date in accordance with paragraph (b)(1) of Rule 15c2-12 adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended ("Rule 15c2-12"). SCPPA shall deliver or cause to be delivered to the Underwriters, within seven (7) business days from the date hereof and, in any event, in sufficient time to accompany any customer confirmations requesting payment, copies of an official statement, dated the date hereof, relating to the Bonds executed on behalf of and approved for distribution by SCPPA in the form of the Preliminary Official Statement, as amended to conform to the terms of this Purchase Contract and to reflect the reoffering terms of the Bonds, and with such other changes as shall have been consented to by SCPPA and acceptable to the Representative (the "Official Statement"). SCPPA shall deliver the Official Statement in such quantities as the Underwriters may request in order to comply with paragraph (b)(4) of Rule 15c2-12 and the rules of the Municipal Securities Rulemaking Board (the "MSRB"). SCPPA shall also prepare and provide or cause to be provided to the Underwriters no later than one (1) business day prior to the Closing Date (as defined in Section 7) an electronic copy of the Official Statement, including any amendments thereto, in word-searchable PDF format as described in the MSRB's Rule G-32 to enable the Underwriters to comply with MSRB Rule G-32. The Representative agrees to deliver a copy of the Official Statement to the MSRB in accordance and to otherwise comply with all applicable MSRB rules.

4. **Public Offering; Determination of Issue Price**.

(a) It shall be a condition to SCPPA's obligation to sell and deliver the Bonds to the Underwriters, and it shall be a condition to the Underwriters' obligation to purchase, to accept delivery of and to pay for the Bonds that the entire aggregate principal amount of the Bonds shall be issued, sold, and delivered by SCPPA and purchased, accepted, and paid for by the

Underwriters on the Closing Date. The Underwriters agree to make a bona fide public offering of all of the Bonds at prices not in excess of the initial, respective public offering prices or at yields not lower than the initial, respective yields shown or derived from information shown on the inside cover of the Official Statement. Except as set forth in subsection (d) below, the Underwriters reserve the right to change such initial offering prices after such offering as they shall deem necessary in connection with the marketing of the Bonds.

(b) The Underwriters agree to assist SCPPA in establishing the issue price of the Bonds and shall execute and deliver to SCPPA at Closing an issue price certificate or similar certificate, together with the supporting pricing wires or equivalent communications, substantially in the form or forms, as applicable, attached hereto as Exhibit E, with such modifications as may be appropriate or necessary, in the reasonable judgment of the Representative, SCPPA, and Nixon Peabody LLP, Special Tax Counsel to SCPPA, to accurately reflect, as applicable, the sales price or prices or the initial offering price or prices to the [public] of the Bonds. All actions to be taken by SCPPA under this section to establish the issue price of the Bonds may be taken on behalf of SCPPA by SCPPA's municipal advisor, PFM Financial Advisors LLC (the "Municipal Advisor"), and any notice or report to be provided to SCPPA may be provided to the Municipal Advisor.

(c) Except for the Hold the Price Maturities described in subsection (d) below and Schedule I attached hereto, SCPPA will treat the first price at which 10% of each maturity of the Bonds (the "10% test") is sold to the public as the issue price of that maturity. For purposes of this Section 4, if Bonds mature on the same date but have different interest rates, each separate CUSIP number within that maturity will be treated as a separate maturity of the Bonds. Schedule I attached hereto sets forth, as of the date of this Purchase Contract, the maturities of the Bonds for which the 10% test has been satisfied (the "10% Test Maturities") and the price or prices at which the Underwriters have sold such 10% Test Maturities to the public.

(d) With respect to the maturities of the Bonds that are not 10% Test Maturities, if any, as described in Schedule I attached hereto (the "Hold the Price Maturities"), the Representative confirms that the Underwriters have offered such maturities of the Bonds to the public on or before the date of this Purchase Contract at the offering price or prices (the "initial offering price"), or at the corresponding yield or yields, set forth on Schedule I attached hereto. SCPPA and the Representative, on behalf of the Underwriters, agree that the restrictions set forth in the next sentence shall apply to the Hold the Price Maturities, which will allow SCPPA to treat the initial offering price to the public of each such maturity as of the sale date as the issue price of that maturity (the "hold the offering price rule"). So long as the hold the offering price rule remains applicable to any maturity of the Bonds, the Underwriters will neither offer nor sell any portion of such maturity of the Hold the Price Maturities to any person at a price that is higher than the initial offering price to the public during the period starting on the sale date and ending on the earlier of the following:

(1) the close of the fifth (5th) business day after the sale date; or

(2) the date on which the Underwriters have sold at least 10% of that maturity of the Hold the Price Maturities to the public at a price that is no higher than the initial offering price to the public.

The Representative will advise SCPPA promptly after the close of the 5th business day after the sale date whether the Underwriters have sold 10% of that maturity of the Hold the Price Maturities to the public at a price that is no higher than the initial offering price to the public.

(e) The Representative confirms that:

(1) any agreement among underwriters, any selling group agreement and each third party distribution agreement (to which the Representative is a party) relating to the initial sale of the Bonds to the public, together with the related pricing wires, contains or will contain language obligating each Underwriter, each dealer who is a member of the selling group, and each broker dealer that is a party to such third party distribution agreement, as applicable, to:

(A) (i) report the prices at which it sells to the public the unsold Bonds of each maturity allotted to it until it is notified by the Representative that either the 10% test has been satisfied as to the Bonds of that maturity or all Bonds of that maturity have been sold to the public, and (ii) comply with the hold the offering price rule, if applicable, in each case if and for so long as directed by the Representative and as set forth in the related pricing wires;

(B) promptly notify the Representative of any sales of Bonds that, to its knowledge, are made to a purchaser who is a related party to an underwriter participating in the initial sale of the Bonds to the public (each such term being used as defined below), and

(C) acknowledge that, unless otherwise advised by the Underwriter, dealer or broker dealer, the Representative shall assume that each order submitted by the Underwriter, dealer or broker dealer is a sale to the public; and

(2) any agreement among underwriters relating to the initial sale of the Bonds to the public, together with the related pricing wires, contains or will contain language obligating each Underwriter that is a party to a third party distribution agreement to be employed in connection with the initial sale of the Bonds to the public to require each broker dealer that is a party to such third party distribution agreement to

(A) report the prices at which it sells to the public the unsold Bonds of each maturity allotted to it until it is notified by the Representative or the Underwriter that either the 10% test has been satisfied as to the Bonds of that maturity or all Bonds of that maturity have been sold to the public; and

(B) comply with the hold the offering price rule, if applicable, in each case if and for so long as directed by the Representative or the Underwriter and as set forth in the related pricing wires

(f) SCPPA acknowledges that, in making the representations set forth in this Section 4, the Representative will rely on:

(1) he agreement of each Underwriter to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, as set forth in an agreement among underwriters and the related pricing wires,

(2) in the event a selling group has been created in connection with the initial sale of the Bonds to the public, the agreement of each dealer who is a member of the selling group to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, as set forth in a selling group agreement and the related pricing wires, and

(3) in the event that an Underwriter or a dealer who is a member of the selling group is a party to a third party distribution agreement that was employed in connection with the initial sale of the Bonds to the public, the agreement of each broker dealer that is a party to such agreement to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, as set forth in the third party distribution agreement and the related pricing wires.

(g) SCPPA further acknowledges that each Underwriter shall be solely liable for its failure to comply with its agreement regarding the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, and that no Underwriter shall be liable for the failure of any other Underwriter, or of any dealer who is a member of a selling group, or of any broker dealer that is a party to a third party distribution agreement, to comply with its corresponding agreement.

(h) The Underwriters acknowledge that sales of any Bonds to any person that is a related party to an underwriter participating in the initial sale of the Bonds to the public (each such term as defined below) shall not constitute sales to the public for purposes of this Section 4.

(i) Further, for purposes of this Section 4:

(1) "public" means any person other than an underwriter or a related party,

(2) "underwriter" (when used with a lower case "u") means:

(i) any person that agrees pursuant to a written contract with SCPPA (or with the lead underwriter to form an underwriting syndicate) to participate in the initial sale of the Bonds to the public, and

(ii) any person that agrees pursuant to a written contract directly or indirectly with a person described in clause (i) to participate in the initial sale of the Bonds to the public (including a member of a selling group or a party to a third party distribution agreement participating in the initial sale of the Bonds to the public),

(3) a purchaser of any of the Bonds is a "related party" to an underwriter if the underwriter and the purchaser are subject, directly or indirectly, to (i) more than 50% common ownership of the voting power or the total value of their stock, if both entities are

corporations (including direct ownership by one corporation of another), (ii) more than 50% common ownership of their capital interests or profits interests, if both entities are partnerships (including direct ownership by one partnership of another), or (iii) more than 50% common ownership of the value of the outstanding stock of the corporation or the capital interests or profit interests of the partnership, as applicable, if one entity is a corporation and the other entity is a partnership (including direct ownership of the applicable stock or interests by one entity of the other), and

(4) "sale date" means the date of execution of this Purchase Contract by all parties.

5. Use and Preparation of Documents. SCPPA hereby authorizes the use (including in designated electronic format as permitted by applicable MSRB rules) by the Underwriters of the Official Statement (including any supplements or amendments thereto) and, subject to any restrictions on the disclosure of their contents contained therein, the Basic Documents (as defined in Section 6(b) hereof), and the information therein contained, in connection with the public offering and sale of the Bonds. SCPPA hereby ratifies and approves the use (including electronic delivery) by the Underwriters prior to the date hereof of the Preliminary Official Statement and the forms of the Indenture and the Renewal Transmission Service Contracts (as defined in Section 6(b) hereof) in connection with the public offering of the Bonds.

6. Representations, Warranties and Agreements. SCPPA hereby represents, warrants and agrees as follows:

(a) SCPPA is an entity duly organized and validly existing pursuant to the Act and that certain Southern California Public Power Authority Joint Powers Agreement, dated as of November 1, 1980, as amended (the "SCPPA Organization Agreement"), among the parties therein named (hereinafter referred to as the "Members"), and the SCPPA Organization Agreement has been duly authorized, executed and delivered by each of the Members in accordance with the Act and other applicable provisions of the Constitution and laws of the State of California and the city charters or other applicable instruments or statutes of or pertaining to the Members;

(b) SCPPA has full legal right, power and authority (i) to enter into this Purchase Contract and to issue, sell and deliver the Bonds to the Underwriters as provided herein; (ii) to carry out and consummate the transactions contemplated by the Indenture, this Purchase Contract, the Disclosure Resolution and the Official Statement; and (iii) to carry out and consummate the transactions contemplated by the Southern Transmission System Agreement, dated as of May 1, 1983, as amended by the First Amendment to the Southern Transmission System Agreement, dated as of November 1, 2008, and as further amended by the Second Amendment to Southern Transmission System Agreement, dated as of March 1, 2023, each between IPA and SCPPA (as so amended, the "Existing Southern Transmission System Agreement"), the Renewal Southern Transmission System Agreement, dated March 1, 2023 (the "Renewal Southern Transmission System Agreement"), between IPA and SCPPA, the Renewal Agreements for the Acquisition of Capacity, dated as of March 1, 2023 (collectively, the "Renewal Capacity Acquisition Agreements"), by and between SCPPA and each of the Department of Water and Power of The City of Los Angeles ("LADWP") and the California cities of Burbank and Glendale (which, together with LADWP, are hereinafter collectively referred to as the "Project Participants"), the

Renewal Transmission Service Contracts, dated as of March 1, 2023 (the “Renewal Transmission Service Contracts”), by and between SCPPA and each of the Project Participants), and the Renewal Agency Agreement, dated as of March 1, 2023 (the “Renewal Agency Agreement”), by and between SCPPA and LADWP (the Existing Southern Transmission System Agreement, the Renewal Southern Transmission System Agreement, the Renewal Capacity Acquisition Agreements, the Renewal Transmission Service Contracts, the Renewal Agency Agreement and the Indenture being herein collectively referred to as the “Basic Documents”); the Basic Documents have all been duly authorized by all necessary action on the part of SCPPA, and, except for those of the Basic Documents which by their terms become effective only upon the consummation of the transactions contemplated under this Purchase Contract, are in full force and effect; SCPPA has complied, or will on the Closing Date be in compliance in all material respects, with the terms of the Act, the SCPPA Organization Agreement and the Basic Documents and with the obligations in connection with the issuance of the Bonds on its part contained in the Bonds and this Purchase Contract; the Basic Documents and this Purchase Contract constitute the legal, valid and binding agreements or obligations of SCPPA, and in the case of the Renewal Capacity Acquisition Agreements, the Renewal Transmission Service Contracts, the Power Sales Contracts, dated as of August 6, 1980, as amended, including as amended by the Second Amendatory Power Sales Contract, dated as of December 8, 2015 (as so amended, the “IPP Existing Power Sales Contracts”), by and between each of LADWP and the California cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (collectively, the “Original Transmission Service Purchasers”) and IPA, and the Renewal Power Sales Contracts, dated as of January 16, 2017, as amended (the “IPP Renewal Power Sales Contracts”), by and between each of the Project Participants and IPA, constitute the legal, valid and binding agreements of the respective Original Transmission Service Purchasers or Project Participants party thereto (as applicable), enforceable in accordance with their respective terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws or equitable principles relating to or limiting creditors’ rights generally and by limitations on legal remedies against public agencies in the State of California; and payments by each of the Original Transmission Service Purchasers under its IPP Existing Power Sales Contract constituting Interim Revenues (as defined in the Indenture), and by each of the Project Participants under its Renewal Transmission Service Contract will constitute an operating expense of the electric utility system of such entity;

(c) By all necessary official action, SCPPA has duly adopted the Disclosure Resolution, has duly authorized the execution and delivery of the Indenture, has duly authorized and approved the preparation and use of the Preliminary Official Statement and the Official Statement to be distributed in connection with the offering, sale and distribution of the Bonds and has duly authorized and approved (i) the execution and delivery of the Bonds, this Purchase Contract and the Basic Documents, (ii) the performance by SCPPA of the obligations in connection with the issuance of the Bonds on its part contained in the Bonds, this Purchase Contract and the Basic Documents, and (iii) the consummation by it of all other transactions contemplated by this Purchase Contract and the Basic Documents in connection with the issuance of the Bonds; the Bonds, when issued and delivered to the Underwriters in accordance with the Indenture and this Purchase Contract, will constitute legal, valid and binding obligations of SCPPA, enforceable in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws or equitable principles relating to or limiting creditors’ rights generally and by limitations on legal remedies against public agencies in the State of California;

(d) SCPPA is not, and will not be, in any material respect in breach of or default under any applicable constitutional provision, law or administrative regulation of the United States or any state thereof or any agency or instrumentality of either or any applicable judgment or decree or any loan agreement, indenture, bond, note, resolution, agreement (including, without limitation, any of the Basic Documents) or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets is otherwise subject, and no event has occurred and is continuing which with the passage of time or the giving of notice, or both, would constitute such a default or event of default under any such instrument, in any case where such breach or default would materially adversely affect (i) the marketability of the Bonds or the market prices thereof, or (ii) SCPPA or its ability to perform its obligations under this Purchase Contract and the Basic Documents; the execution and delivery of the Bonds, this Purchase Contract and the Basic Documents, and compliance with the provisions on SCPPA's part contained therein, will not conflict with or constitute a breach of or default under any constitutional provision, law, administrative regulation, judgment, decree, loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets is otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, this Purchase Contract or the Basic Documents or the validity or enforceability thereof, nor will any such execution, delivery, adoption or compliance result in the creation or imposition of any lien, charge or other security interest or encumbrance of any nature whatsoever upon any of the property or assets of SCPPA or under the terms of any such law, provision, regulation or instrument, except as provided by the Bonds, the Indenture and the other Basic Documents;

(e) All authorizations, approvals, licenses, permits, consents and orders of any governmental authority, legislative body, board, agency or commission having jurisdiction of the matter which are required for the due authorization by, or which would constitute a condition precedent to or the absence of which would materially adversely affect the due performance by, SCPPA of its obligations in connection with the issuance of the Bonds under this Purchase Contract or under the Indenture have been duly obtained, except for such approvals, consents and orders as may be required under the Blue Sky or securities laws of any state in connection with the offering and sale of the Bonds; and, except as described in or contemplated by the Preliminary Official Statement and the Official Statement, all authorizations, approvals, licenses, permits, consents and orders of any governmental authority, board, agency or commission having jurisdiction of the matter which are required for the due authorization by, or which would constitute a condition precedent to or the absence of which would materially adversely affect the due performance by, SCPPA of its respective obligations under this Purchase Contract and the Basic Documents have been duly obtained, except those which need not be obtained until a future date;

(f) The Bonds when issued will conform to the descriptions thereof contained in the Preliminary Official Statement (except for the omission of certain information permitted to be omitted therefrom in accordance with Rule 15c2-12) and the Official Statement under the captions "INTRODUCTION" and "DESCRIPTION OF THE 2024-1 BONDS"; the Indenture, when executed, will conform to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions "INTRODUCTION," "DESCRIPTION OF THE 2024-1 BONDS" and "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS" and contained in APPENDIX C thereto; the Renewal Transmission Service Contracts will conform to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions “INTRODUCTION” and “SECURITY AND SOURCES OF PAYMENT FOR THE BONDS” and contained in APPENDIX C thereto; the Existing Southern Transmission System Agreement, the Renewal Southern Transmission System Agreement, the Renewal Capacity Acquisition Agreements and the IPP Existing Power Sales Contracts conform to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions “INTRODUCTION” and “SECURITY AND SOURCES OF PAYMENT FOR THE BONDS” and contained in APPENDIX C thereto; the IPP Renewal Power Sales Contracts conform to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions “INTRODUCTION” and contained in APPENDIX C thereto; the SCPPA Organization Agreement conforms to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions “INTRODUCTION” and “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY”; and the Renewal Agency Agreement conforms to the description thereof contained in the Preliminary Official Statement and the Official Statement under the caption “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY” and contained in Appendix C thereto;

(g) The Bonds, when issued, authenticated and delivered in accordance with the Indenture and sold to the Underwriters as provided herein, will be validly issued and outstanding obligations of SCPPA, entitled to the benefits of the Indenture; and upon such issuance and delivery, the Indenture will provide, for the benefit of the owners from time to time of the Bonds, the legally valid and binding pledge and lien and security interest it purports to create;

(h) Between the date of this Purchase Contract and the Closing Date, SCPPA will not, without the prior written consent of the Representative, offer or issue any notes, bonds or other obligations for borrowed money, or incur any material liabilities, direct or contingent, with respect to the Southern Transmission System Renewal Project, except in the course of normal business operations of SCPPA or except for refinancings for savings on outstanding bonds or except for such borrowings as may be described in or contemplated by the Official Statement or otherwise disclosed in writing to the Representative, nor will there be any adverse change of a material nature in the financial position, results of operations or condition, financial or otherwise, of SCPPA;

(i) As of the date hereof, except for the litigation (A) described or referred to in the Preliminary Official Statement and the Official Statement under the caption “LITIGATION,” and the subcaption “Litigation” under the caption “The Department of Water and Power of the City of Los Angeles” contained in APPENDIX A thereto, or (B) otherwise disclosed in writing to the Representative on or before the date of this Purchase Contract, there is no action, suit, proceeding, inquiry or investigation, at law or in equity before or by any court, government agency, public board or body, pending or, to the knowledge of the officer of SCPPA executing this Purchase Contract, threatened against SCPPA (nor to the best knowledge of such officer is there any such action, suit, proceeding, inquiry or investigation pending or threatened against any Project Participant or Original Transmission Service Purchaser), affecting the existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain or enjoin the sale, issuance or delivery of the Bonds or the collection of the revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the Revenues or other funds and accounts to be established pursuant to the Indenture, or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, this Purchase Contract or any Basic Document or the IPP Existing Power

Sales Contracts or IPP Renewal Power Sales Contracts, or contesting the tax-exempt status of interest on the Bonds for federal or State of California income tax purposes, or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement, or contesting the powers of SCPPA or any authority for the issuance of the Bonds or the execution and delivery or adoption, as applicable, by SCPPA of this Purchase Contract or any Basic Document, or in any way contesting or challenging the consummation of the transactions contemplated hereby or thereby, or which would result in a material adverse change in the financial condition of SCPPA or which would materially adversely affect the transmission capacity of the Southern Transmission System or the acquisition and construction of the Southern Transmission System Renewal Project; nor, to the best knowledge of SCPPA, is there any basis for any such action, suit, proceeding, inquiry or investigation, wherein an unfavorable decision, ruling or finding would materially adversely affect the validity of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or this Purchase Contract;

(j) SCPPA will furnish such information, execute such instruments and take such other action in cooperation with the Underwriters as the Representative may reasonably request in order (i) to qualify the Bonds for offer and sale under the Blue Sky or other securities laws and regulations of such states and other jurisdictions of the United States as the Representative may designate, and (ii) to determine the eligibility of the Bonds for investment under the laws of such states and other jurisdictions, and will use its best efforts to continue such qualifications in effect so long as required for the distribution of the Bonds; provided, however, that SCPPA shall not be required to execute a general or special consent to service of process or qualify to do business in connection with any such qualification or determination in any jurisdiction;

(k) As of its date and at the time of SCPPA's acceptance hereof, the Preliminary Official Statement (as supplemented and amended, if applicable) was and is true, complete, correct and final in all material respects, except for the omission of certain information permitted to be omitted therefrom in accordance with Rule 15c2-12, and did not and does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(l) At the time of delivery thereof to the Underwriters and (unless an event occurs of the nature described in paragraph (n) of this Section 6) at all times subsequent thereto to and including the Closing Date, the Official Statement will be true, complete, correct and final in all material respects and will not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(m) If the Official Statement is supplemented or amended pursuant to paragraph (n) of this Section 6, at the time of each supplement or amendment thereto and (unless subsequently again supplemented or amended pursuant to such paragraph) at all times subsequent thereto to and including the Closing Date, the Official Statement as so supplemented or amended will not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(n) If between the date of this Purchase Contract and that date which is 25 days after the end of the underwriting period (as determined in accordance with Section 15 hereof) any event shall occur or be discovered by SCPPA affecting SCPPA, the Revenues pledged or to be pledged to pay the principal of and interest on the Bonds or the Project Participants which might adversely affect the marketability of the Bonds or the market prices thereof, or which might cause the Official Statement, as then supplemented or amended, to contain any untrue statement of a material fact or to omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading, SCPPA shall notify the Representative thereof (and shall provide to the Representative such information concerning such event as the Representative may reasonably request) and, if in the opinion of the Representative such event requires the preparation and publication of a supplement or amendment to the Official Statement, SCPPA will at its expense prepare and furnish to the Underwriters a reasonable number of copies of such supplement to, or amendment of, the Official Statement, in a form and in a manner approved by the Representative;

(o) The charges to be made by SCPPA for transmission service sold to the Project Participants under the Renewal Transmission Service Contracts are not subject to regulation by any authority of the State of California or the United States;

(p) Interest on the Bonds will be exempt from California personal income taxation under existing statutes, regulations, rulings and court decisions, and the federal income tax treatment of interest on the Bonds will be as described in the form of opinion of Special Tax Counsel included in the Official Statement as Appendix F thereto;

(q) SCPPA will apply the proceeds from the sale of the Bonds for the purposes specified in the Official Statement;

(r) SCPPA has not failed during the previous five years to comply in any material respect with any previous undertakings in any written continuing disclosure contract or agreement under Rule 15c2-12; and

(s) Any certificate signed by an official of SCPPA authorized to do so in connection with the transactions described in this Purchase Contract and delivered pursuant to Section 8(e) shall be deemed a representation by SCPPA to the Underwriters as to the statements made therein.

7. Closing. At 8:00 a.m., Los Angeles time, on May 9, 2024 or at such earlier or later time or date as shall be mutually agreed upon by SCPPA and the Representative (such time and date being herein referred to as the "Closing Date"), SCPPA will, subject to the terms and conditions hereof, sell and deliver the Bonds to or for the account of the Underwriters in definitive form, duly executed and authenticated, together with the other documents hereinafter mentioned, and, subject to the terms and conditions hereof, the Underwriters will accept such delivery and pay the purchase price of the Bonds as set forth in Section 1 hereof by federal funds wire or certified or official bank check or checks in federal funds immediately available in Los Angeles, California to the order of SCPPA. Sale, delivery and payment as aforesaid shall be made at the offices of Norton Rose Fulbright US LLP, 555 South Flower Street, 41st Floor, Los Angeles, California, or such other place as shall have been mutually agreed upon by SCPPA and the Representative, except that the Bonds shall be delivered through the facilities of The Depository Trust Company

("DTC") in New York, New York, or at such other place as shall have been mutually agreed upon by SCPPA and the Representative, in fully registered, book-entry eligible form (which may be typewritten) and registered in the name of Cede & Co. as nominee of DTC.

8. Closing Conditions. The Underwriters have entered into this Purchase Contract in reliance upon the representations and warranties of SCPPA contained herein, and in reliance upon the representations and warranties to be contained in the documents and instruments to be delivered pursuant hereto on or prior to the Closing Date and upon the performance by SCPPA of its obligations hereunder, both as of the date hereof and as of the Closing Date. Accordingly, the Underwriters' obligations under this Purchase Contract to purchase, to accept delivery of and to pay for the Bonds shall be conditioned upon the performance by SCPPA of its obligations to be performed hereunder and under such documents and instruments on or prior to the Closing Date, and shall also be subject to the following additional conditions:

(a) The representations and warranties of SCPPA contained herein shall be true, complete and correct on the date hereof and on and as of the Closing Date, as if made on the Closing Date;

(b) As of the Closing Date, the SCPPA Organization Agreement, each of the Basic Documents, the IPP Existing Power Sales Contracts and the IPP Renewal Power Sales Contracts shall be in full force and effect in accordance with their respective terms and, shall not have been amended, modified or supplemented, and the Official Statement shall not have been supplemented or amended, except in any such case as may have been agreed to by the Representative;

(c) As of the Closing Date, all necessary official action of SCPPA and of the other parties thereto relating to this Purchase Contract, the SCPPA Organization Agreement and the Basic Documents shall have been taken and shall be in full force and effect and shall not have been amended, modified or supplemented in any material respect, except in any such case as may have been agreed to by the Representative;

(d) As of the Closing Date, there shall not have occurred any change in or affecting particularly SCPPA or the Project Participants, the Bonds, the Revenues, the status of construction, required permits, licenses or approvals relating to the Southern Transmission System Renewal Project, or arrangements for financing for the Southern Transmission System Renewal Project by SCPPA, as the foregoing matters are described in the Official Statement, which in the opinion of the Representative materially impairs the investment quality or marketability of the Bonds;

(e) On or prior to the Closing Date, the Representative, on behalf of the Underwriters, shall have received a copy of each of the following documents:

(1) The Official Statement and each supplement or amendment, if any, thereto, executed on behalf of SCPPA by its President, Vice President or Executive Director;

(2) A copy of each of the Basic Documents as executed by the parties thereto;

(3) The approving legal opinion, dated the Closing Date and addressed to SCPPA, of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel to SCPPA, substantially in the form included in the Official Statement as Appendix E thereto;

(4) The opinion, dated the Closing Date and addressed to SCPPA, of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel to SCPPA, substantially in the form included in the Official Statement as Appendix F thereto;

(5) An opinion, dated the Closing Date and addressed to the Underwriters, of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel and Disclosure Counsel to SCPPA, substantially in the form attached hereto as Exhibit A;

(6) An opinion, dated the Closing Date and addressed to the Underwriters, of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel to SCPPA, substantially in the form attached hereto as Exhibit F.

(7) An opinion, dated the Closing Date and addressed to the Underwriters, of General Counsel to SCPPA, substantially in the form attached hereto as Exhibit C;

(8) A certificate, dated the Closing Date, signed by the President, Vice President or Executive Director of SCPPA, substantially in the form attached hereto as Exhibit C (but in lieu of or in conjunction with paragraph 2 of such certificate the Representative may, in its sole discretion, accept certificates or opinions of Norton Rose Fulbright US LLP, Los Angeles, California, or of other counsel acceptable to the Representative, that in the opinion of such counsel the issues raised in any pending or threatened litigation referred to in such certificate are without substance or that the contentions of all plaintiffs therein are without merit);

(9) Certificates, dated the Closing Date, signed by an authorized representative of each of the Department and the Cities of Burbank and Glendale, with respect to certain matters, including with respect to the Department, the information pertaining to it contained in the Preliminary Official Statement and the Official Statement, such certificate of the Department being substantially in the form attached hereto as Exhibit D-1 and the certificates of each of the Cities of Burbank and Glendale being substantially in the form attached hereto as Exhibit D-2;

(10) An opinion, dated the Closing Date and addressed to the Underwriters, of Hawkins Delafield & Wood LLP, counsel for the Underwriters, to the effect that (i) the Bonds are not subject to the registration requirements of the Securities Act of 1933, as amended, and the Indenture is exempt from qualification pursuant to the Trust Indenture Act of 1939, as amended, (ii) based upon the participation of such firm in the preparation of the Preliminary Official Statement and the Official Statement, as the case may be, and without having undertaken to determine independently the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement, nothing has come to the attention of the attorneys in such firm rendering legal services in connection with such representation that caused them to believe that the Preliminary Official Statement, as of its date and as of April 25, 2024, or the Official Statement, as of its date and as of the Closing Date (excluding the financial statements or other financial or statistical data or forecasts and the information concerning DTC and the book-entry only system, the discussions of permits, licenses and approvals required for the construction and operation of Intermountain Power Project, including the Southern

Transmission System Renewal Project, or the other activities or projects of SCPPA or other projects of the Project Participants, and the status of each, the description of any litigation, the financial and statistical information with respect to the Project Participants contained in the Preliminary Official Statement and the Official Statement, and Appendices B through F thereto, as to all of which no opinion is expressed), contained or contains an untrue statement of material fact or omitted or omits to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading; and (iii) assuming the due authorization and adoption of the Disclosure Resolution by SCPPA and the enforceability thereof, the Disclosure Resolution satisfies clause (b)(5)(i) of Rule 15c2-12 of the Securities Exchange Act, which requires an undertaking for the benefit of the holders, including beneficial owners, of the Bonds to provide annual updates of certain Official Statement information and certain event notices to the MSRB at the times and in the manner required by such Rule;

(11) A transcript of all proceedings relating to the authorization and issuance of the Bonds certified by the Secretary or an Assistant Secretary of SCPPA, including the Disclosure Resolution;

(12) An opinion of counsel to each of the Project Participants, dated the Closing Date and addressed to SCPPA and the Underwriters, in substantially the form attached as Exhibit B to the Renewal Transmission Service Contacts, and including, among other things, the opinion of such counsel to the effect that the IPP Renewal Power Sales Contract, the Renewal Capacity Acquisition Agreement and the Renewal Transmission Service Contract executed by such Project Participant have been duly authorized, executed and delivered and constitute the legal, valid and binding obligation of such Project Participant, enforceable against such Project Participant in accordance with their respective terms;

(13) A letter from counsel to each of the Original Transmission Service Purchasers, dated the Closing Date and addressed to SCPPA and the Underwriters, confirming as of the Closing Date, and entitling the Underwriters to rely upon, the conclusions contained in the opinions of such counsel to the effect that the IPP Existing Power Sales Contract executed by such Original Transmission Service Purchaser has been duly authorized, executed and delivered and constitutes the legal, valid and binding obligation of such Original Transmission Service Purchaser, enforceable against such Original Transmission Service Purchaser in accordance with its terms;

(14) An opinion, dated the Closing Date and addressed to SCPPA and the Underwriters, of counsel to the Trustee, in form and substance acceptable to SCPPA and the Representative, to the effect that the Trustee is duly authorized to execute, deliver and perform its obligations under the Indenture, and that the same is valid, binding and enforceable against the Trustee in accordance with its terms; and

(15) Such additional legal opinions, certificates, instruments and other documents as the Representative may reasonably request to evidence the truth and accuracy, as of the date hereof and as of the Closing Date, of SCPPA's representations and warranties contained herein and of the statements and information contained in the Official Statement and the due performance or satisfaction by SCPPA on or prior to the Closing

Date of all the agreements then to be performed and conditions then to be satisfied by it; and

(f) The Bonds shall have been rated at least [“Aa2” and “AA–”] by Moody’s Investors Service, Inc. and Fitch Ratings, Inc., respectively, and neither such rating shall have been suspended, revoked or downgraded.

All the opinions, letters, certificates, instruments and other documents mentioned above or elsewhere in this Purchase Contract shall be deemed to be in compliance with the provisions hereof if, but only if, they are in form and substance satisfactory to the Representative; provided, however, the opinions and certificates referred to in subparagraphs (3), (4), (5), (6), (7), (8) and (9) of paragraph (e) of this Section, inclusive, shall be deemed satisfactory provided they are substantially in the respective forms attached as an appendix to the Official Statement or as exhibits to this Purchase Contract, as applicable.

If SCPPA shall be unable to satisfy the conditions to the obligations of the Underwriters to purchase, to accept delivery of and to pay for the Bonds contained in this Purchase Contract, or if the obligations of the Underwriters to purchase, to accept delivery of and to pay for the Bonds shall be terminated for any reason permitted by this Purchase Contract, this Purchase Contract shall terminate and neither the Underwriters nor SCPPA shall be under any further obligation hereunder, except that the respective obligations of SCPPA and the Underwriters set forth in Sections 10 and 12 hereof shall continue in full force and effect.

9. Termination. The Underwriters shall have the right to terminate its obligations under this Purchase Contract to purchase, to accept delivery of and to pay for the Bonds by the Representative notifying SCPPA of their election to do so if, after the execution hereof and prior to the Closing Date:

(i) an event or circumstance shall occur or be discovered which makes untrue or incorrect in any material respect, any statement or information contained in the Preliminary Official Statement or the Official Statement or which is not reflected in the Official Statement but should be reflected therein in order to make the statements contained therein in the light of the circumstances under which they were made not misleading in any material respect and, in either such event, (a) SCPPA refuses to permit the Official Statement to be supplemented to supply such statement or information in a manner satisfactory to the Representative or (b) the effect of the Official Statement as so supplemented is, in the reasonable judgment of the Representative, to materially adversely affect the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(ii) legislation shall be enacted by the State of California or by the United States, recommended to the legislature of the State of California by the Governor or to the Congress for passage by the President of the United States, or favorably reported for passage to either house of the legislature of the State of California or either house of the Congress by any committee of any such house to which such legislation has been referred for consideration, or a decision shall be rendered by any court of the State of California or the United States of competent jurisdiction, or a ruling or regulation (final, temporary or proposed) shall be issued on behalf of the Treasury Department of the United States, the Internal Revenue Service or any other authority of the United States, affecting the tax-exempt status of SCPPA or the interest on its bonds or its notes (including the Bonds) for federal or State of California income tax purposes which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(iii) any action shall have been taken by (a) the Securities and Exchange Commission or by a court of competent jurisdiction which would require registration of the Bonds under the Securities Act of 1933, as amended, or qualification of any indenture under the Trust Indenture Act of 1939, as amended, in connection with the public offering of the Bonds or the effect of which is that the issuance, offering or sale of the Bonds as contemplated would be in violation of the federal securities laws as amended and in effect; or (b) any court or by any governmental authority suspending the offering or sale of the Bonds or the use of the Official Statement or any amendment or supplement thereto; or

(iv) there shall have been (1) a declaration of war or engagement in or escalation of military hostilities by the United States or any act of terrorism or (2) any other calamity or crisis (or material escalation in any calamity or crisis), which in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(v) there shall have occurred the declaration of a general banking moratorium by any authority of the United States or the States of New York or California or a material disruption in commercial banking or securities settlement or clearance services or payment services shall have occurred which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(vi) there shall have occurred a general suspension of trading, minimum or maximum prices for trading shall have been fixed and be in force or maximum ranges or prices for securities shall have been required on the New York Stock Exchange or other national stock exchange whether by virtue of a determination by that Exchange or by order of the Securities and Exchange Commission or any other governmental agency having jurisdiction or any national securities exchange shall have (a) imposed additional material restrictions not in force as of the date hereof with respect to trading in securities generally, or to the Bonds or similar obligations; or (b) materially increased restrictions now in force with respect to the charge to the net capital requirements of Underwriters or broker dealers which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(vii) there shall have been a downgrading, suspension or withdrawal of the rating on the Bonds, or the rating on the Bonds shall have been placed on "credit watch" or "negative outlook" or similar qualification.

10. Expenses. (a) The Underwriters shall be under no obligation to pay, and SCPPA shall pay, any expenses incident to the performance of SCPPA's obligations hereunder including, but not limited to: (i) the cost of preparation and printing of the Indenture, the Preliminary Official Statement and the Official Statement and any supplements or amendments thereto; (ii) the cost of preparation and printing of the Bonds; (iii) the fees and disbursements of Norton Rose Fulbright US LLP, Bond Counsel to SCPPA, Nixon Peabody LLP, Special Tax Counsel to SCPPA, and the fees and expenses of counsel to SCPPA; (iv) the fees and disbursements, if any, of the Trustee; (v) the fees and disbursements of PFM Financial Advisors LLC for its services as financial advisor to SCPPA with regards to the Southern Transmission System Renewal Project; (vi) the fees and disbursements of any engineers, accountants and other experts, consultants or advisers retained by SCPPA or providing letters, opinions or reports to SCPPA or the Underwriters pursuant to this Purchase Contract; (vii) fees for bond ratings; (viii) the cost of preparation and printing of this Purchase Contract and the Blue Sky Memorandum; (ix) all advertising expenses and Blue Sky filing fees in connection with the public offering of the Bonds; (x) any expenses for air travel, hotel costs, meals and transportation for SCPPA employees in connection with the pricing of the Bonds, any investor meetings, any rating agency trips and the Closing; and (xi) any other miscellaneous Closing costs. SCPPA acknowledges that it has had an opportunity, in consultation with such advisors as it may deem appropriate, if any, to evaluate and consider the fees and expenses being incurred as part of the issuance of the Bonds.

(b) SCPPA has agreed to pay the Underwriters' discount set forth in Section 1 of this Purchase Contract, and inclusive in the expense component of the Underwriters' discount are expenses incurred or paid for by the Underwriters on behalf of SCPPA in connection with the marketing, issuance, and delivery of the Bonds, including, but not limited to, advertising expenses, fees and expenses of Underwriters' Counsel, the costs of any Preliminary and Final Blue Sky Memoranda, fees payable to the California Debt and Investment Advisory Commission, CUSIP Global Services and DTC in connection with the issuance of the Bonds, and transportation, lodging, and meals for SCPPA's employees and representatives in connection with the sale and issuance of the Bonds.

SCPPA and the Representative acknowledge that expenses included in the expense component of the Underwriters' discount are based upon estimates. SCPPA and the Representative agree that in the event the aggregate estimated expenses exceed the aggregate actual expenses incurred by the Representative in an amount equal to or greater than $1,000 (the "Reimbursement Threshold"), the Representative shall reimburse to SCPPA the aggregate amount of expenses equal to or greater than the Reimbursement Threshold. For the avoidance of doubt, SCPPA acknowledges and agrees that in the event the aggregate estimated expenses exceed the aggregate actual expenses incurred by the Representative in an amount less than the Reimbursement Threshold, no reimbursement will be made by the Representative. SCPPA acknowledges that it has had an opportunity, in consultation with such advisors as it may deem appropriate, if any, to evaluate and consider the fees and expenses being incurred as part of the issuance of the Bonds.

(c) Notwithstanding the foregoing, if the Underwriters or SCPPA shall bring an action to enforce any part of this Purchase Contract against the other, each party shall bear its attorneys' fees and costs incurred in connection with such action.

11. Notices. Any notice or other communication to be given to SCPPA under this Purchase Contract may be given by delivering the same in writing at SCPPA's address set forth above, and any notice or other communication to be given to the Underwriters under this Purchase Contract may be given by delivering the same in writing to the Representative as Barclays Capital Inc., 745 Seventh Avenue, 19th Floor, New York, NY 10019, Attention: John Daniel.

12. Parties in Interest. This Purchase Contract is made solely for the benefit of SCPPA and the Underwriters (including the successors or assigns of the Underwriters) and no other person shall acquire or have any right hereunder or by virtue hereof. All of SCPPA's representations, warranties and agreements contained in this Purchase Contract shall remain operative and in full force and effect, regardless of: (i) any investigations made by or on behalf of the Underwriters; (ii) delivery of and payment for the Bonds pursuant to this Purchase Contract; and (iii) any termination of this Purchase Contract.

13. Effectiveness. This Purchase Contract shall become effective upon the execution of the acceptance by the President, any Vice President, the Executive Director or the Chief Financial and Administrative Officer of SCPPA and shall be valid and enforceable at the time of such acceptance.

14. Headings. The headings of the sections of this Purchase Contract are inserted for convenience only and shall not be deemed to be a part hereof.

15. End of Underwriting Period. The term "end of the underwriting period" referred to in Section 6(n) of this Purchase Contract shall mean the later of such time as (i) SCPPA delivers the Bonds to the Underwriters and (ii) the Underwriters does not retain an unsold balance of the Bonds for sale to the public. Unless the Representative gives notice to the contrary, the end of the underwriting period shall be deemed to be the Closing Date. Any notice delivered pursuant to this Section 15 shall be delivered in writing to SCPPA at or prior to the Closing Date, and shall specify a date, other than the Closing Date (or such other date previously specified by notice delivered pursuant to this Section 15), to be deemed the end of the underwriting period. In no event, without the prior agreement of SCPPA, shall the end of the underwriting period be a date more than 30 days after the Closing Date.

16. Counterparts. This Purchase Contract may be executed in several counterparts, each of which shall be regarded as an original and all of which shall constitute one and the same document.

17. Representation By Counsel; Drafting. The Underwriters and SCPPA each acknowledge that it has been represented by counsel in negotiating and drafting this Purchase Contract. Each provision of this Purchase Contract shall be construed with the recognition that both parties participated in the drafting of the same. Thus, any rule of construction that requires this Purchase Contract to be construed against the drafting party shall not be applicable.

18. Arm's Length Commercial Transaction. The primary role of the Underwriters is to purchase the Bonds for resale to investors, in an arm's length commercial transaction between SCPPA and the Underwriters. The Underwriters and SCPPA acknowledge and agree that (i) the purchase and sale of the Bonds pursuant to this Purchase Contract is an arm's-length commercial transaction between SCPPA, on the one hand, and the Underwriters, on the other hand, (ii) in connection with such transaction and with the discussions, undertakings and procedures leading up to the consummation of such transaction, each Underwriter is and has been acting solely as a principal and not as a municipal advisor, a financial advisor, or a fiduciary of SCPPA, and may have financial and other interests that differ from those of SCPPA, (iii) the Underwriters have not assumed (individually or collectively) a fiduciary responsibility in favor of SCPPA with respect to the offering of the Bonds or the discussions, undertakings and procedures leading thereto (whether or not any Underwriter, or any affiliate of an Underwriter, has provided or is currently providing services or advice to SCPPA on other matters), (iv) the only obligations the Underwriters have to SCPPA with respect to the transactions contemplated hereby are expressly set forth in this Purchase Contract, and (v) SCPPA and the Underwriters have consulted with their respective legal, financial, accounting, tax and other advisors to the extent they deemed appropriate in connection with the offering of the Bonds. None of the Underwriters is acting as a Municipal Advisor (as defined in Section 15B of the Exchange Act of 1934, as amended) in connection with the matters contemplated by this Purchase Contract.

19. Compensation. The Underwriters acknowledge and agree that (1) the compensation received by the Underwriters in connection with this Purchase Contract was determined pursuant to an arm's length transaction as specified in Section18 above; (2) no other compensation received for such services was received from sources other than proceeds of the Bonds; and (3) such compensation only covers services in connection with the issuance of the Bonds and this Purchase Contract.

20. Governing Law. This Purchase Contract shall be construed in accordance with the laws of the State of California. Any action arising hereunder shall be filed and maintained in Los Angeles County, California.

21. Severability. If any provision of this Purchase Contract shall be held to be invalid, illegal or unenforceable in any respect, then such provision shall be deemed severable from the remaining provisions contained in this Purchase Contract and such invalidity, illegality or unenforceability shall not affect any other provision of this Purchase Contract.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

22. Entire Agreement; Amendments. This Purchase Contract constitutes the entire agreement between the parties hereto with respect to the matters covered hereby, and supersedes all prior agreements and understandings between the parties. This Purchase Contract shall only be amended, supplemented or modified in a writing signed by both of the parties hereto.

Very truly yours,

BARCLAYS CAPITAL INC.
RBC CAPITAL MARKETS, LLC
BOFA SECURITIES, INC.
LOOP CAPITAL MARKETS LLC
SAMUEL A. RAMIREZ & CO., INC.
SIEBERT WILLIAMS SHANK & CO., LLC
TD SECURITIES (USA) LLC

By: Barclays Capital Inc.,
as Representative of the Underwriters

By: ____
Managing Director

Accepted on this __ day of April, 2024:

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By: ___________________________________
Chief Financial and
Administrative Officer

SCHEDULE I

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES AND PRICES OR YIELD

$______________

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	Price

[C] Price to par call date of July 1, 20[__].
[*] 10% Test Maturities.
[**] Hold-the-Price Maturities.

SCHEDULE II

REDEMPTION PROVISIONS

Optional Redemption. The Bonds maturing on and after July 1, ____ are subject to redemption prior to maturity, at the option of SCPPA, from any source of available funds, in whole or in part (and, if in part, from such maturities as SCPPA shall direct), on any date on or after July 1, ____, at a redemption price equal to the principal amount of the Bonds, or portions thereof, to be redeemed, without premium, in each case together with accrued interest to the redemption date.

Mandatory Sinking Fund Redemption. The Bonds maturing on July 1, ____ are subject to mandatory sinking fund redemption, on July 1 of each of the years set forth in the following table in the respective redemption amounts set forth opposite such years in said table (together with accrued interest thereon), without premium:

2024-1 Bonds
Maturing on July 1, ____

Redemption Date (July 1)	Redemption Amount

† Maturity.

The Bonds maturing on July 1, ____ are subject to mandatory sinking fund redemption, on July 1 of each of the years set forth in the following table in the respective redemption amounts set forth opposite such years in said table (together with accrued interest thereon), without premium:

2024-1 Bonds
Maturing on July 1, ____

Redemption Date (July 1)	Redemption Amount

† Maturity.

In connection with any optional redemption of any Bonds that are term bonds, the principal amount of such Bonds being redeemed shall be allocated against the scheduled sinking fund redemption amounts set forth above in such manner as the Authority may direct and the scheduled sinking fund installments payable thereafter shall be modified as to such Bonds. In such event, the Authority shall provide to the Trustee a revised schedule of sinking fund installments.

EXHIBIT A

Opinion to the Underwriters of Bond and Disclosure Counsel

[Letterhead of Norton Rose Fulbright LLP]

[Closing Date]

Barclays Capital Inc.
RBC Capital Markets, LLC
BofA Securities, Inc.
Loop Capital Markets LLC
Samuel A. Ramirez & Co., Inc.
Siebert Williams Shank & Co., LLC
TD Securities (USA) LLC
c/o Barclays Capital Inc.,
as Representative of the Underwriters

Re: Southern California Public Power Authority
<u>Southern Transmission System Renewal Project, Revenue Bonds, 2024-1</u>

Ladies and Gentlemen:

This letter is delivered to you, as underwriters, pursuant to Section 8(e)(5) of the Purchase Contract, dated April 25, 2024 (the "Purchase Contract"), between Barclays Capital Inc., as your Representative, and Southern California Public Power Authority (the "Authority").

As used herein, the terms "Basic Documents," "Indenture," "Preliminary Official Statement," "Official Statement," "Renewal Transmission Service Contract," "Renewal Capacity Acquisition Agreement," "IPP Existing Power Sales Contracts," "IPP Renewal Power Sales Contracts," "Original Transmission Service Purchasers" and "Project Participants," shall have the respective meanings ascribed thereto in the Purchase Contract.

We deliver herewith a copy of our opinion, dated the date hereof and addressed to the Authority, as to the validity of the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, issued in the aggregate principal amount of $______________ (the "Bonds"). This will confirm that you may rely upon such opinion as if the same were addressed to you. We express no view or opinion as to the validity or binding or enforceable nature of any of the Basic Documents, except as set forth in such opinion.

We are of the opinion that:

1. The Bonds are not subject to the registration requirements of the Securities Act of 1933, as amended, and the Indenture is exempt from qualification pursuant to the Trust Indenture Act of 1939, as amended;

2. The statements contained in the Preliminary Official Statement and the Official Statement under the captions "INTRODUCTION," "DESCRIPTION OF THE

2024-1 BONDS" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS" and contained in APPENDIX C thereto (excluding the statements under each such caption relating to The Depository Trust Company ("DTC"), Cede & Co. or the book-entry only system, as to all of which we express no view), insofar as the statements contained under such captions purport to summarize certain provisions of the Bonds, the Indenture, the Renewal Transmission Service Contracts, and the other Basic Documents, the IPP Existing Power Sales Contracts and the IPP Renewal Power Sales Contracts and our opinion concerning certain tax matters relating to the Bonds, present an accurate summary of such provisions and opinion for the purpose of use in the Preliminary Official Statement and the Official Statement;

3. No order, filing, consent, approval, exemption of or registration with any governmental authority (other than such filings or registration as have been completed or orders, consents, or approvals as have been obtained) is required in connection with the execution and delivery by the Authority of the Bonds, the Indenture, the Renewal Transmission Service Contracts or the other Basic Documents;

4. Under the Constitution and laws of the State of California, each IPP Existing Power Sales Contract, IPP Renewal Power Sales Contract, Renewal Capacity Acquisition Agreement and Renewal Transmission Service Contract constitutes a valid and binding agreement of the Original Transmission Service Purchaser or Project Participant party thereto (as applicable) enforceable in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid, binding and enforceable nature of such agreements and contracts: (i) the legal existence or formation of any Original Transmission Service Purchaser or Project Participant or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of any Original Transmission Service Purchaser or Project Participant, including, without limitation, any proceedings relating to the negotiation or authorization of any IPP Existing Power Sales Contract, IPP Renewal Power Sales Contract, Renewal Capacity Acquisition Agreement or Renewal Transmission Service Contract, or the execution, delivery or performance thereof (except that we have examined the respective ordinances and resolutions pursuant to which such agreements and contracts were authorized by the respective Original Transmission Service Purchasers and Project Participants), (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such agreements or contracts) or any governmental order, regulation or rule of or applicable to any Original Transmission Service Purchaser or Project Participant, (iv) any judicial order, judgment or decree in a proceeding to which any Original Transmission Service Purchaser or Project Participant is a party, or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Original Transmission Service Purchaser or Project Participant of its IPP Existing Power Sales Contract, IPP Renewal Power Sales Contract, Renewal Capacity Acquisition Agreement or Renewal Transmission Service Contract. The Authority has heretofore received, independent from this opinion, opinions with respect to, among other things, the validity and enforceability of the IPP Existing Power Sales Contracts, IPP Renewal Power Sales Contracts, Renewal Capacity

Acquisition Agreements and Renewal Transmission Service Contracts rendered by legal counsel to the respective Original Transmission Service Purchasers and Project Participants; and

5. The Purchase Contract has been duly authorized, executed and delivered by the Authority, and assuming due authorization, execution and delivery by the other party thereto, constitutes a legal, valid and binding agreement of the Authority.

The opinions expressed in paragraphs 4 and 5 hereof are qualified to the extent that the enforceability of the IPP Existing Power Sales Contracts, the IPP Renewal Power Sales Contracts, the Renewal Capacity Acquisition Agreements, the Renewal Transmission Service Contracts and the Purchase Contract may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights generally, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases or as to the availability of a particular remedy. In addition, the enforceability of the IPP Existing Power Sales Contracts, the IPP Renewal Power Sales Contracts, the Renewal Capacity Acquisition Agreements, the Renewal Transmission Service Contracts and the Purchase Contract is subject to the effect of general principles of equity, including, without limitation, concepts of materiality, reasonableness, good faith and fair dealing, to the possible unavailability of specific performance or injunctive relief, regardless of whether considered in a proceeding in equity or at law, and to the limitations on legal remedies against public agencies in the State of California. We express no opinion as to any indemnification, contribution, penalty, choice of law, choice of forum or waiver provisions contained in the foregoing documents.

Based upon our participation in the preparation of the Preliminary Official Statement and the Official Statement as Bond Counsel and Disclosure Counsel to SCPPA and upon the information made available to us in the course of the foregoing, but without having undertaken to determine or verify independently or assuming any responsibility for the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement (except to the extent expressly set forth in paragraph 2 above), as of the date hereof, nothing has come to the attention of the personnel directly involved in rendering legal advice and assistance in connection with the preparation of the Preliminary Official Statement and the Official Statement that causes us to believe that (a) the Preliminary Official Statement, as of its date or as of April 25, 2024, contained any untrue statement of a material fact or omitted to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom the discussions contained in the Preliminary Official Statement of permits, licenses and approvals required for the construction and operation of the Southern Transmission System Renewal Project (as defined in the Preliminary Official Statement) or other activities of the Authority or other projects of the Authority or the Project Participants, and the status thereof, the description of any litigation, any information relating to DTC, Cede & Co., the book-entry only system, the financial, statistical and other information with respect to the Project Participants, forecasts, projections, estimates, assumptions and expressions of opinions and the other financial and statistical data included therein and information under the caption "TAX MATTERS", as to all of which we express no view) and except for such information as is permitted to be excluded from the Preliminary Official Statement pursuant to Rule 15c2-12 of the Securities Exchange Act of 1934, as amended, including, but not limited to information as to pricing, yields, interest rates, maturities, amortization, redemption provisions, debt service requirements, underwriters' discount and CUSIP numbers, or (b) the Official Statement, as of its date or as of the date hereof, contained or contains any untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom the discussions contained in the Official Statement of permits, licenses and approvals required for the construction and operation of the Southern Transmission System Renewal Project (as defined in the Official Statement) or other activities of the Authority or other projects of the Authority or the Project Participants, and the status thereof, the description of any litigation, any information relating to DTC, Cede & Co., the book-entry only system, the financial, statistical and other information with respect to the Project Participants, forecasts, projections, estimates, assumptions and expressions of opinions and the other financial and statistical data included therein and information under the caption "TAX MATTERS", as to all of which we express no view).

During the period from the date of the Preliminary Official Statement to the date of this opinion, except for our review of the certificates and opinions regarding the Preliminary Official Statement and the Official Statement delivered on the date hereof, we have not undertaken any procedures or taken any actions which were intended or likely to elicit information concerning the accuracy, completeness or fairness of any of the statements contained in the Preliminary Official Statement or the Official Statement.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions. Such opinions may be adversely affected by actions taken or events occurring, including a change in law, regulation or ruling (or in the application or official interpretation of any law, regulation or ruling) after the date hereof. We have not undertaken to determine, or to inform any person, whether such actions are taken or such events occur, and we have no obligation to update this opinion in light of any such actions or events.

We are furnishing you this letter at the request of the Authority and solely for the information of, and assistance to, you in conducting and documenting your investigation of the affairs of the Authority in connection with the offering of the Bonds and it is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of the Bonds, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that it may be included in, and reference may be made to it in any list of, the closing documents pertaining to the delivery of the Bonds. The provision of this opinion letter to you shall not create any attorney-client relationship between our firm and you. This opinion letter may not be relied upon by any other person, firm, corporation or other entity without our prior written consent, and we have no obligation to update this opinion.

Very truly yours,

EXHIBIT B

[Opinion to the Underwriters of Counsel to SCPPA]

[Letterhead of Counsel to SCPPA]

[Closing Date]

Barclays Capital Inc.
RBC Capital Markets, LLC
BofA Securities, Inc.
Loop Capital Markets LLC
Samuel A. Ramirez & Co., Inc.
Siebert Williams Shank & Co., LLC
TD Securities (USA) LLC
c/o Barclays Capital Inc.,
as Representative of the Underwriters

Re: Southern California Public Power Authority
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

Ladies and Gentlemen:

I am General Counsel to Southern California Public Power Authority ("SCPPA"), a joint exercise of powers agency organized and existing pursuant to Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the "Act"). This opinion is rendered pursuant to Section 8(e)(7) of the Purchase Contract, dated April 25, 2024 (the "Purchase Contract"), by and between SCPPA and Barclays Capital Inc., as representative (the "Representative") of the underwriters named therein (the "Underwriters") relating to the sale of $______________ aggregate principal amount of SCPPA's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "Bonds").

As used herein the terms "SCPPA Organization Agreement," "Indenture," "Basic Documents," "Renewal Transmission Service Contracts," "IPP Existing Power Sales Contracts," "IPP Renewal Power Sales Contracts," "Renewal Capacity Acquisition Agreements," "Original Transmission Service Purchasers," "Project Participants," "Cede & Co.," "DTC," "Preliminary Official Statement," and "Official Statement," shall have the respective meanings ascribed thereto in the Purchase Contract.

I am of the opinion that:

1. SCPPA is a joint powers authority duly organized and validly existing under the Act and the SCPPA Organization Agreement, and has full legal right, power and authority to execute and deliver, and to perform its obligations under, the Basic Documents and the Purchase Contract.

2. Assuming the due authorization, execution and delivery of the SCPPA Organization Agreement by the parties thereto (the "Members"), the SCPPA Organization

Agreement constitutes the legal, valid and binding obligation of the Members, enforceable against the Members in accordance with its terms.

3. The Purchase Contract and the Basic Documents have been duly authorized, executed and delivered by SCPPA, and, assuming due authorization, execution and delivery by each of the other respective parties thereto, the Purchase Contract and the Basic Documents constitute the legal, valid and binding obligations of SCPPA, enforceable against SCPPA in accordance with their respective terms.

4. Except as disclosed in the Preliminary Official Statement and the Official Statement, no order, filing, consent, approval, exemption of or registration with any governmental authority (other than such filings or registrations as have been completed or orders, consents or approvals as have been obtained) is required in connection with the execution and delivery by SCPPA of the Bonds, the Basic Documents or the Purchase Contract; provided, however, that no opinion is expressed with respect to qualification of the Bonds for sale under blue sky or other state securities laws.

5. The statements contained in the Preliminary Official Statement and the Official Statement under the caption "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY" present a fair and accurate description of SCPPA for the purpose of use in the Preliminary Official Statement and the Official Statement, respectively.

6. SCPPA is not in material breach of or default under any applicable constitutional provision, law or administrative regulation of the State of California or the United States or any applicable judgment or decree or any loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets are otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof, and no event has occurred and is continuing which with the passage of time or the giving of notice, or both, would constitute a material default or event of default under any such instrument, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof.

7. The execution and delivery of the Bonds, the Purchase Contract and the Basic Documents and compliance with the provisions on SCPPA's part contained therein, will not conflict with or constitute a material breach of or default under any constitutional provision, law, administrative regulation, judgment, decree, loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets are otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof, nor will any such execution, delivery, adoption or compliance result in the creation or imposition of any lien, charge or other security interest or encumbrance of any nature whatsoever upon any of the property or assets of SCPPA or under the terms of any such

provision, law, regulation, resolution or instrument, except as provided by the Bonds, the Indenture and the other Basic Documents.

8. The charges to be made by SCPPA for transmission service sold to the Project Participants under the Renewal Transmission Service Contracts are not subject to regulation by any authority of the State of California or the United States.

9. As of the date hereof, except as described in the Preliminary Official Statement and the Official Statement under the caption "LITIGATION" or otherwise disclosed in writing to the Representative, to the best of my knowledge, there is no action, suit, proceeding, inquiry or investigation, at law or in equity, before or by any court, government agency, public board or body, pending or threatened against SCPPA affecting the corporate existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain, or enjoin the issuance or delivery of the Bonds or the collection of the Revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the revenues, funds and accounts established pursuant to the Indenture, or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, the Purchase Contract or any Basic Document, or SCPPA's ability to perform its obligations and transactions under the Basic Documents, or contesting the tax-exempt status of interest on the Bonds for federal or State of California income tax purposes or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement or any supplement or amendment thereto, or contesting the powers of SCPPA or any authority for the issuance of the Bonds, or the execution and delivery by SCPPA of the Purchase Contract or any Basic Document, nor, to the best of my knowledge, is there any basis for any such action, suit, proceeding, inquiry or investigation wherein any unfavorable decision, ruling or finding would materially adversely affect the validity or enforceability of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or the Purchase Contract.

Based upon my participation in the preparation of the Preliminary Official Statement and the Official Statement as counsel for SCPPA and without having undertaken to determine independently the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement (except to the extent expressly set forth in paragraph 5 above), as of the date hereof, nothing has come to my attention which would cause me to believe that: (A) the Preliminary Official Statement, as of its date and as of April 25, 2024 (as supplemented or amended pursuant to paragraph (n) of Section 6 of the Purchase Contract, if applicable), contained any untrue statement of a material fact or omitted to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading (except for the discussion contained in the Preliminary Official Statement of permits, licenses and approvals required for the construction and operation of the Southern Transmission System Renewal Project (as defined in the Preliminary Official Statement), or other activities of SCPPA or other projects of the Project Participants, and the status of each, any information relating to DTC, Cede & Co. or the book-entry only system, the financial, statistical and other information with respect to the Project Participants and the other financial and statistical data included therein, as to all of which I express no view); or (B) the Official Statement, as of its date and as of the date hereof (as supplemented or amended pursuant to paragraph (n) of Section 6 of the Purchase Contract, if applicable), contained or contains any untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading (except for the discussion contained in the Official Statement of permits, licenses and approvals required for the construction and operation of the Southern Transmission System Renewal Project (as defined in the Official Statement), or other activities of SCPPA or other projects of the Project Participants, and the status of each, any information relating to DTC, Cede & Co. or the book-entry only system, the financial, statistical and other information with respect to the Project Participants and the other financial and statistical data included therein, as to all of which I express no view).

Insofar as the foregoing opinions relate to the legal, valid and binding effect, and the enforceability, of any instrument, such opinions are subject to applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally, and are subject, as to enforceability, to general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law), to the exercise of judicial discretion in appropriate cases, and to the limitations on legal remedies against public agencies in the State of California. Also, a court may refuse to enforce a provision if it deems that such provision is in violation of public policy.

The opinions expressed herein are based upon the laws and other matters in effect on the date hereof. The opinions expressed are matters of professional judgment and are not a warranty or guarantee of result. I assume no obligation to revise or supplement this opinion letter should any law be changed by legislative action, judicial decision or otherwise, or should any facts or other matters upon which I have relied be changed.

The opinions which are set forth or which are expressed herein are limited to the laws of the State of California and the federal laws of the United States.

The opinions herein are furnished exclusively to the above recipients to whom this opinion letter is addressed. This opinion letter may not be provided to, made available to, or relied upon by any other party.

Respectfully submitted,

Christine Godinez
General Counsel
Southern California Public Power Authority

EXHIBIT C

CERTIFICATE OF SCPPA

I, [__________], Executive Director of Southern California Public Power Authority ("SCPPA"), **DO HEREBY CERTIFY** as follows:

1. The representations and warranties of SCPPA contained in the Purchase Contract, dated April 25, 2024, by and between SCPPA and Barclays Capital Inc., as representative (the "Representative") of the underwriters named therein (the "Purchase Contract") with respect to the sale by SCPPA of its Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 issued in the aggregate principal amount of $______________ (the "Bonds"), are true and correct in all material respects on and as of the date hereof as if made on this date.

2. As of the date hereof, except for the litigation (A) described or referred to in the Preliminary Official Statement of SCPPA, dated April 19, 2024 (the "Preliminary Official Statement"), and in the Official Statement of SCPPA, dated April 25, 2024 (the "Official Statement"), relating to the Bonds, under the caption "LITIGATION" and the subcaption "Litigation" under the caption "The Department of Water and Power of the City of Los Angeles" contained in APPENDIX A thereto, or (B) otherwise disclosed in writing to the Representative, there is no action, suit, proceeding, inquiry or investigation, at law or in equity before or by any court, government agency, public board or body, pending or, to my knowledge, threatened against SCPPA (nor to the best of my knowledge is there any such action, suit, proceeding, inquiry or investigation pending or threatened against any Project Participant or Original Transmission Service Purchaser), affecting the existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain or enjoin the sale, issuance or delivery of the Bonds or the collection of the revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the Revenues (as defined in the Indenture) or other funds and accounts to be established pursuant to the Indenture, or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, the Purchase Contract, any Basic Document or the IPP Existing Power Sales Contracts or IPP Renewal Power Sales Contracts, or contesting the tax exempt status of interest on the Bonds for federal or California income tax purposes, or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement or any supplement or amendment thereto, or contesting the powers of SCPPA or any authority for the issuance of the Bonds or the execution and delivery or adoption by SCPPA of the Purchase Contract or any Basic Document, or in any way contesting or challenging the consummation of the transactions contemplated thereby, or which might result in a material adverse change in the financial condition of SCPPA or which might materially adversely affect the transmission capacity of the Southern Transmission System or the acquisition and construction of the Southern Transmission System Renewal Project (as such terms are defined in the Preliminary Official Statement and the Official Statement); nor, to the best

of my knowledge, is there any basis for any such action, suit, proceeding, inquiry or investigation, wherein an unfavorable decision, ruling or finding would materially adversely affect the validity of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or the Purchase Contract.

3. To the best of my knowledge, no event affecting SCPPA or the Southern Transmission System Renewal Project has occurred since the date of the Official Statement which should be disclosed in the Official Statement so that the Official Statement will not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading, and which has not been disclosed in a supplement or amendment to the Official Statement.

4. SCPPA has complied with all the agreements and satisfied all the conditions on its part to be performed or satisfied at or prior to the date hereof pursuant to the Purchase Contract with respect to the issuance of the Bonds.

All capitalized terms used herein which are not otherwise defined shall have the same meanings as in the Purchase Contract.

Dated: [Closing Date]

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By: ____
[_________]
Executive Director
Southern California Public Power Authority

EXHIBIT D-1

CERTIFICATE OF THE DEPARTMENT OF WATER AND POWER

I, Ann M. Santilli, Chief Financial Officer of the Department of Water and Power of the City of Los Angeles (the "Department"), hereby certify on behalf of the Department as of the date hereof, that:

1. This certificate is furnished to the Underwriters pursuant to Section 8(e)(9) of the Purchase Contract, dated April 25, 2024 (the "Purchase Contract"), by and between Southern California Public Power Authority ("SCPPA") and Barclays Capital Inc., as representative (the "Representative") of the underwriters named therein (the "Underwriters"), relating to the sale by SCPPA of its Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "Bonds"), as more fully described in the Preliminary Official Statement, dated April 19, 2024 (the "Preliminary Official Statement"), and the Official Statement, dated April 25, 2024 (the "Official Statement"), of SCPPA prepared in connection with the sale of said Bonds.

2. To my knowledge, the ordinance of the City Council of the City of Los Angeles referenced in Attachment 1 hereto: (i) is in full force and effect; (ii) has not been amended, rescinded, supplemented or modified; and (iii) is not the subject of any actual or threatened, legal or administrative action by or before any court, commission, regulatory agency, arbitrator, mediator, negotiator, governmental entity (federal, state, municipal or other) or any other tribunal or body established to resolve disputes or enforce applicable constitutions, laws, ordinances, regulations, rules, customs or practices.

3. I have read the Preliminary Official Statement and the Official Statement and to my knowledge, but without having made an independent investigation, the Preliminary Official Statement as of its date and as of April 25, 2024, and the Official Statement as of its date and as of the date hereof, including APPENDIX A thereto, as to matters known or made known to me relating to the Department did not and does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

4. The description of the business and properties of the power system of the Department included in the Preliminary Official Statement, including APPENDIX A thereto, as of its date and as of April 25, 2024, and in the Official Statement, including APPENDIX A thereto, as of the date of the Official Statement and as of the date hereof (in each case, including the data, schedules and statistics pertaining to the operations of the power system of the Department but excluding the financial statements, schedules and other financial data included therein), did not and does not contain an untrue statement of a material fact or omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading.

5. The financial information regarding the power system of the Department contained in the Preliminary Official Statement and the Official Statement, including APPENDIX A thereto, fairly presents in all material respects the financial position and results of operations of such power

system as of the dates and for the periods set forth therein and, to the undersigned's knowledge, the financial statements of the power system of the Department included therein have been prepared in accordance with generally accepted accounting principles consistently applied and, except as otherwise indicated in the Preliminary Official Statement and Official Statement, based upon the audited financial statements of the power system of the Department.

6. Other than as set forth in the Preliminary Official Statement and the Official Statement, no litigation is pending against the Department with service of process against the Department having been made, or, to the knowledge of the undersigned, overtly threatened in writing in any way, (i) contesting or impairing the validity of the IPP Existing Power Sales Contract, the IPP Renewal Power Sales Contract, the Renewal Capacity Acquisition Agreement or the Renewal Transmission Service Contract to which the Department is a party, or the Renewal Agency Agreement, or the performance by the Department of the provisions thereof, or (ii) involving the Department or its Power Assets (as defined in the City of Los Angeles City Charter) which would result in any material adverse change in the Power Revenue Fund (as defined in the City of Los Angeles City Charter) of the Department, other than routine litigation of the type which normally accompanies the construction and/or operation of municipal electric facilities.

7. The obligations of the Department to make payments under the Renewal Transmission Service Contract constitute a cost of transmission service and an operating expense of the Department payable solely from its electric revenue funds.

8. The obligations of the Department to make payments to Intermountain Power Agency under the IPP Existing Power Sales Contract and the IPP Renewal Power Sales Contract constitute a cost of purchased electricity and energy and an operating expense of the Department payable solely from its electric revenue funds.

9. The Department hereby acknowledges its obligation and agrees that, upon the occurrence of any of the following events with respect to the Department, the Department shall give notice of the occurrence of such event to SCPPA not later than five (5) business days after the occurrence of the event, together with all such information concerning such Financial Obligation (as defined below) of the Department, as may be necessary for SCPPA to satisfy its notice obligations under Resolution No. 2024-___, adopted by the Board of Directors of SCPPA on April 18, 2024, relating to the provision of certain continuing disclosure information with respect to the Bonds:

> (i) incurrence of a Financial Obligation of the Department, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of the Department, any of which affect holders of the Bonds, if material; or
>
> (ii) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Department, any of which reflect financial difficulties.

For purposes of this paragraph 8, the term “Financial Obligation” shall mean (a) a debt obligation; (b) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (c) guarantee of a debt obligation or any such derivative instrument; provided that "financial obligation" shall not include municipal securities as to which a final official statement (as defined in Rule 15c2-12 adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the "Rule")) has been provided to the Municipal Securities Rulemaking Board consistent with the Rule.

This Certificate is solely for the information of, and assistance to, SCPPA and the Underwriters in conducting and documenting their investigation of the matters covered by the Official Statement in connection with the offering pursuant thereto, and is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of securities, nor is it to be referred to in whole or in part in the Official Statement or any other document, except that references may be made to it in the Purchase Contract or in any list of closing documents pertaining to such offering.

All capitalized terms used herein shall have the respective meanings set forth in the Purchase Contract.

Dated: [Closing Date]

DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

By: ______________________________________
Ann M. Santilli
Chief Financial Officer

EXHIBIT D-2

CERTIFICATE OF PROJECT PARTICIPANT
[(Burbank)] [(Glendale)]

I, ________________________ [Title] of the City of [Burbank, California ("Burbank")] [Glendale, California ("Glendale")], hereby certify that:

1. This certificate is furnished to the Underwriters pursuant to Section 8(e)(9) of the Purchase Contract, dated April 25, 2024 (the "Purchase Contract"), by and between Southern California Public Power Authority ("SCPPA") and Barclays Capital Inc., as representative (the "Representative") of the underwriters named therein (the "Underwriters"), relating to the sale by SCPPA of its Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "Bonds"), as more fully described in the Preliminary Official Statement, dated April 19, 2024 (the "Preliminary Official Statement"), and the Official Statement, dated April 25, 2024 (the "Official Statement"), of SCPPA prepared in connection with the sale of said Bonds.

2. The action [or actions] of the City Council of the City of [Burbank] [Glendale] referenced in Attachment 1 hereto authorizing the execution and delivery by the City of [Burbank] [Glendale] of its Renewal Capacity Acquisition Agreement and Renewal Transmission Service Contract with SCPPA: (i) [is][are] in full force and effect; (ii) [has][have] not been amended, rescinded, supplemented or modified; and (iii) [is][are] not the subject of any known, or after due inquiry, threatened, legal or administrative action by or before any court, commission, regulatory agency, arbitrator, mediator, negotiator, governmental entity (federal, state, municipal or other) or any other tribunal or body established to resolve disputes or enforce applicable constitutions, laws, ordinances, regulations, rules, customs or practices.

3. Other than as set forth in the Preliminary Official Statement and the Official Statement or otherwise disclosed in writing to the Representative, no litigation is pending or, to the knowledge of the undersigned, after reasonable investigation, threatened in any way contesting or affecting (i) the validity of the IPP Existing Power Sales Contract, the IPP Renewal Power Sales Contract, the Renewal Capacity Acquisition Agreement or the Renewal Transmission Service Contract to which [Burbank] [Glendale] is a party or the performance by [Burbank] [Glendale] of the provisions thereof, or involving [Burbank] [Glendale] or (ii) any of the property or assets which comprise the electric plant of [Burbank] [Glendale] which involves the possibility of any judgment or uninsured liability which may result in any material adverse change in the business, properties or assets or in the condition, financial or otherwise, of the electric department or electric plant of [Burbank] [Glendale], other than routine litigation of the type which normally accompanies the construction and/or operation of municipal electric facilities.

4. [Burbank][Glendale]'s IPP Existing Power Sales Contract and IPP Renewal Power Sales Contract with IPA, and Renewal Capacity Acquisition Agreement and Renewal Transmission Service Contract with SCPPA are in full force and effect, and neither [Burbank][Glendale] nor, to the best of my current actual knowledge, after due investigation, IPA or SCPPA (as applicable) is in default of its obligations thereunder.

5. The obligations of [Burbank] [Glendale] to make payments under the Renewal Transmission Service Contract constitute a cost of transmission service and an operating expense of [Burbank][Glendale] payable solely from its electric revenue funds.

6. The obligations of [Burbank] [Glendale] to make payments to IPA under the IPP Existing Power Sales Contract and the IPP Renewal Power Sales Contract constitute a cost of purchased electricity and energy and an operating expense of [Burbank] [Glendale] payable solely from its electric revenue funds.

This Certificate is solely for the information of, and assistance to, SCPPA and the Underwriters in conducting and documenting their investigation of the matters covered by the Preliminary Official Statement and the Official Statement in connection with the offering pursuant thereto, and is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of securities, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that reference may be made to it in the Purchase Contract or in any list of closing documents pertaining to such offering.

All capitalized terms used herein shall have the meanings set forth in the Purchase Contract.

Dated: [Closing Date], 2024

CITY OF [BURBANK] [GLENDALE]

By:______________________________________
[Title]

EXHIBIT E

[FORM OF ISSUE PRICE CERTIFICATE]

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

$______________

Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

UNDERWRITER'S CERTIFICATE

The undersigned, on behalf of Barclays Capital Inc. (the "**Representative**"), on behalf of itself and RBC Capital Markets, LLC, BofA Securities, Inc., Loop Capital Markets LLC, Samuel A. Ramirez & Co., Inc., Siebert Williams Shank & Co., LLC and TD Securities (USA) LLC (together with the Representative, the "**Underwriting Group**"), hereby certifies as set forth below with respect to the sale and issuance of the above-captioned obligations (the "**Bonds**").

[**Appropriate provisions to be selected based on results of sale of Bonds**]:

* * *

1. **Sale of the General Rule Maturities**. As of the date of this certificate, for each Maturity of the [General Rule Maturities/Bonds], the first price at which at least 10% of such Maturity of the Bonds was sold to the Public (the "Sale Price") is the respective price listed in Schedule A.

2. ***Initial Offering Price of the Hold-the-Offering-Price Maturities***.

(a) [The Underwriting Group offered the [Hold-the-Offering-Price Maturities/Bonds] to the Public for purchase at the respective initial offering prices listed in Schedule A (the "**Initial Offering Prices**") on or before the Sale Date. A copy of the pricing wire or equivalent communication for the Bonds is attached to this certificate as Schedule B.]

(b) As set forth in the Purchase Contract for the Bonds, the members of the Underwriting Group have agreed in writing that, (i) for each Maturity of the Hold-the-Offering-Price Maturities, they would neither offer nor sell any of the Bonds of such Maturity to any person at a price that is higher than the Initial Offering Price for such Maturity during the Holding Period for such Maturity (the "**hold-the-offering-price rule**"), and (ii) any selling group agreement shall contain the agreement of each dealer who is a member of the selling group, and any retail distribution agreement shall contain the agreement of each broker-dealer who is a party to the retail distribution agreement, to comply with the hold-the-offering-price rule. Pursuant to such agreement, no Underwriter (as defined below) has offered or sold any Maturity of the Hold-the-Offering-Price Maturities at a price that is higher than the respective Initial Offering Price for that Maturity of the Bonds during the Holding Period.

3. [***Issue Price***. The aggregate of the Sale Prices of the General Rule Maturities and the Initial Offering Prices of the Hold-the-Offering-Price Maturities is $[______] (the "Issue Price").]

4. ***Defined Terms***.

(a) [*General Rule Maturities* means those Maturities of the Bonds listed in Schedule A hereto as the "General Rule Maturities."]

(b) [*Hold-the-Offering-Price Maturities* means those Maturities of the Bonds listed in Schedule A hereto as the "Hold-the-Offering-Price Maturities."]

(c) *[Holding Period* means, with respect to a Hold-the-Offering-Price Maturity, the period starting on the Sale Date and ending on the earlier of (i) the close of the fifth business day after the Sale Date ([DATE]), or (ii) the date on which the Underwriters have sold at least 10% of such Hold-the-Offering-Price Maturity to the Public at prices that are no higher than the Initial Offering Price for such Hold-the-Offering-Price Maturity.]

(d) *Issuer* means Southern California Public Power Authority.

(e) *Maturity* means Bonds with the same credit and payment terms. Bonds with different maturity dates, or Bonds with the same maturity date but different stated interest rates, are treated as separate maturities.

(f) *Public* means any person (including an individual, trust, estate, partnership, association, company, or corporation) other than an Underwriter or a related party to an Underwriter. The term "related party" for purposes of this certificate generally means any two or more persons who have greater than 50 percent common ownership, directly or indirectly.

(g) *Sale Date* means the first day on which there is a binding contract in writing for the sale of a Maturity of the Bonds. The Sale Date of the Bonds is [DATE].

(h) *Underwriter* means (i) any person that agrees pursuant to a written contract with the Issuer (or with the lead underwriter to form an underwriting syndicate) to participate in the initial sale of the Bonds to the Public, and (ii) any person that agrees pursuant to a written contract directly or indirectly with a person described in clause (i) of this paragraph to participate in the initial sale of the Bonds to the Public (including a member of a selling group or a party to a retail distribution agreement participating in the initial sale of the Bonds to the Public).

5. **Yield**.

(a) **No Discount Maturities**. No Maturity was sold at an original issue discount.

(b) **Premium Maturities Subject to Optional Redemption**. The Maturities that mature in the year[s] 20__ are the only Maturities that are subject to optional redemption before maturity and have an Initial Offering Price or Sale Price, as applicable, that exceeds their stated redemption price at maturity by more than one fourth of 1% multiplied by the product of their stated redemption price at maturity and the number of complete years to their first optional redemption date. Accordingly, in computing the Yield on the Bonds stated below in paragraph [7(d)], each such Maturity was treated as retired on its optional redemption date or at maturity to result in the lowest yield on that Maturity. No Maturity is subject to optional redemption within five years of the Delivery Date of the Bonds.]

(c) **No Stepped Coupon Maturities**. No Maturity bears interest at an increasing interest rate.

(d) **Yield**. The Yield on the Bonds is [-]%, being the discount rate that, when used in computing the present worth of all payments of principal and interest to be paid on the Bonds, computed on the basis of a 360-day year and semi-annual compounding, produces an amount equal to the Issue Price of the Bonds as stated above in paragraph [-] [computed with the adjustments stated above in paragraph [-]].

6. **Weighted Average Maturity**. We have been asked to calculate the weighted average maturity of the Bonds in the following manner: divide (a) the sum of the products determined by taking the issue price of each maturity times the number of years from the date hereof to the date of such maturity (determined separately for each maturity and by taking into account mandatory redemptions), by (b) the aggregate issue price of such Bonds. Based solely on these calculations, the weighted average maturity of the Bonds is [-] years.

(signature page follows)

The representations set forth in this certificate are limited to factual matters and the accuracy of certain computations only. Nothing in this certificate represents the Representative's interpretation of any laws, including specifically Sections 103 and 148 of the Internal Revenue Code of 1986, as amended, and the Treasury Regulations thereunder. The undersigned understands that the foregoing information will be relied upon by the Issuer with respect to certain of the representations set forth in the Tax Certificate as to Arbitrage and the Provisions of Sections 141-150 of the Internal Revenue Code of 1986, and with respect to compliance with the federal income tax rules affecting the Bonds, and by Nixon Peabody LLP, Special Tax Counsel to the Issuer, in connection with rendering its opinion that the interest on the Bonds is excluded from gross income for federal income tax purposes, the preparation of Internal Revenue Service Form 8038-G, and other federal income tax advice it may give to the Issuer from time to time relating to the Bonds.

Barclays Capital Inc., for itself and on behalf of the Underwriters

By: ________________________________
Managing Director

SCHEDULE A

SALE PRICES OF THE GENERAL RULE MATURITIES AND

INITIAL OFFERING PRICES OF THE HOLD-THE-OFFERING-PRICE MATURITIES

(*Attached*)

SCHEDULE B

PRICING WIRE OR EQUIVALENT COMMUNICATION

(*Attached*)

EXHIBIT F

Opinion to the Underwriters of Special Tax Counsel

[Letterhead of Nixon Peabody LLP]

[Closing Date]

Barclays Capital Inc.
RBC Capital Markets, LLC
BofA Securities, Inc.
Loop Capital Markets LLC
Samuel A. Ramirez & Co., Inc.
Siebert Williams Shank & Co., LLC
TD Securities (USA) LLC
c/o Barclays Capital Inc.,
as Representative of the Underwriters

Re: Southern California Public Power Authority
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

Ladies and Gentlemen:

This letter is delivered to you, as underwriters, pursuant to Section 8(e)(6) of the Purchase Contract, dated April 25, 2024 (the "Purchase Contract"), between Barclays Capital Inc., as your Representative, and Southern California Public Power Authority (the "Authority").

We deliver herewith a copy of our opinion, dated the date hereof and addressed to the Authority, as to certain tax matters pertaining to the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, issued in the aggregate principal amount of $______________ (the "Bonds"). This will confirm that you may rely upon such opinion as if the same were addressed to you.

We are of the opinion that the statements in the Preliminary Official Statement and the Official Statement under the caption "TAX MATTERS", Appendix F –"PROPOSED FORMS OF SPECIAL TAX COUNSEL OPINION", and in the first paragraph of the cover of the Preliminary Official Statement and Official Statement, to the extent such statements purport to summarize certain provisions of federal or state tax law, are fair and accurate summaries of such provisions.

We are furnishing you this letter at the request of the Authority and solely for the information of, and assistance to, you in conducting and documenting your investigation of the affairs of the Authority in connection with the offering of the Bonds and it is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of the Bonds, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that it may be included in, and reference may be made to it in any list of, the closing documents pertaining to the delivery of the Bonds. The provision of this opinion letter to you shall not create any attorney-client relationship between either of our firms and you. This opinion letter may not be relied upon by any other person, firm, corporation or other entity without our prior written consent, and we have no obligation to update this opinion.

Very truly yours,

PRELIMINARY OFFICIAL STATEMENT DATED __________, 2024

NEW ISSUE – BOOK-ENTRY ONLY

Ratings: Moody's: "[__]"
Fitch: "[__]"
(See "RATINGS" herein.)

In the opinion of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel, under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by the Authority described herein, interest on the 2024-1 Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code. Special Tax Counsel is further of the opinion that interest on the 2024-1 Bonds is exempt from personal income taxes of the State of California (the "State") under present State law. See "TAX MATTERS" herein regarding certain other tax considerations.

$[PAR AMOUNT]*

Southern California Public Power Authority

(a public entity organized under the laws of the State of California)

Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

Dated: Date of Delivery — Due: July 1, as shown on the inside cover

This cover page contains certain information for general reference only. It is not intended to be a summary of the security for or terms of this issue. Investors are advised to read the entire Official Statement to obtain information essential to making an informed investment decision. Capitalized terms used on this cover page not otherwise defined shall have the meanings set forth herein.

The Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "2024-1 Bonds") will be issued by the Southern California Public Power Authority (the "Authority") under and pursuant to an Indenture of Trust, dated as of April 1, 2023, from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"), as previously supplemented and as supplemented by the Third Supplemental Indenture of Trust, dated as of May 1, 2024, from the Authority to the Trustee. Such Indenture of Trust, as so supplemented, is herein referred to as the "Indenture."

The 2024-1 Bonds are being issued to (i) finance a portion of the costs of acquisition and construction of capital improvements to the Southern Transmission System, an approximately 488-mile power transmission line and related facilities, which constitute part of the Intermountain Power Project (such improvements are part of the "Project" and part of the "Southern Transmission System Renewal Project," all as further described herein), (ii) fund capitalized interest on the 2024-1 Bonds and (iii) pay costs of issuance relating to the 2024-1 Bonds. See "ESTIMATED SOURCES AND USES OF FUNDS" and "SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT" herein. *The Southern Transmission System Renewal Project is to be distinguished from the Authority's existing Southern Transmission Project.*

The 2024-1 Bonds will be issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository of the 2024-1 Bonds. Purchasers of the 2024-1 Bonds will not receive physical certificates representing their interest in the 2024-1 Bonds purchased. Individual purchases of the 2024-1 Bonds will be made in book-entry form only, in denominations of $5,000 principal amount or any integral multiple thereof. Interest on the 2024-1 Bonds is payable semiannually on January 1 and July 1 of each year, commencing July 1, 2024. Principal of, premium, if any, and interest on, the 2024-1 Bonds are payable directly to DTC by the Trustee. Upon receipt of payments of such principal, premium, if any, and interest, DTC is obligated to remit such principal, premium, if any, and interest to its DTC participants for subsequent disbursement to the beneficial owners of the 2024-1 Bonds. See "BOOK-ENTRY ONLY SYSTEM" herein.

The 2024-1 Bonds are subject to redemption prior to maturity as described herein.

The 2024-1 Bonds are special, limited obligations of the Authority payable solely from and secured, as to payment of the principal or redemption price thereof, and interest thereon, solely by a pledge and assignment of the Revenues and certain other moneys described herein. Revenues consist primarily of payments to be made to the Authority by the Department of Water and Power of The City of Los Angeles ("LADWP") and the California cities of Burbank and Glendale (which, together with LADWP, are hereinafter collectively referred to as the "Project Participants"), for Bond debt service due on or after the Transition Date (as defined herein), pursuant to the respective Renewal Transmission Service Contracts, between the Authority and such Project Participants, as more fully described herein. Pursuant to the Renewal Transmission Service Contracts, the payments to be made by the applicable Project Participant thereunder will constitute operating expenses of the Project Participant's electric system. The payment obligations of a Project Participant under its Renewal Transmission Service Contract are not contingent upon the completion of the Southern Transmission System Renewal Project or any part thereof, the operation of the Southern Transmission System or the performance or nonperformance by any party of any agreement for any cause whatsoever. Revenues also include Interim Revenues (as defined herein) during the period to, but excluding, the Transition Date. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS" herein.

The Authority has reserved its right to issue additional parity bonds under the Indenture and to enter into Parity Swaps on the terms and conditions and for the purposes stated in the Indenture.

The 2024-1 Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any of the Project Participants or any other member of the Authority and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024-1 Bonds. The Authority has no taxing power.

Maturity Schedule
(see inside cover)

The 2024-1 Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel, and certain other conditions. Certain legal matters will be passed on for the

* Preliminary, subject to change.

Authority by its General Counsel, Christine Godinez, Esq. and by Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel, and for the Underwriters by their counsel, Hawkins Delafield and Wood LLP, Sacramento, California. PFM Financial Advisors LLC is serving as Municipal Advisor to the Authority in connection with the issuance of the 2024-1 Bonds. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2024-1 Bonds. It is expected that the 2024-1 Bonds will be available for delivery through the facilities of DTC in New York, New York, by Fast Automated Securities Transfer (FAST) on or about ______, 2024.

Barclays Capital Inc.	**RBC Capital Markets**

BofA Securities, Inc.	**Loop Capital Markets LLC**	**Ramirez & Co., Inc.**	**Siebert Williams Shank & Co., LLC**	**TD Securities**

Dated: ________, 2024

Maturity Schedule*

$[PAR AMOUNT]
Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

$_________ Serial Bonds

Due July 1	Principal Amount	Interest Rate	Yield	Price	CUSIP†
	$	%	%		

$_________ ____% Term Bonds due July 1, 20__, Yield: ____%; Price: _____CUSIP*: _________

$_________ ____% Term Bonds due July 1, 20__, Yield: ____%; Price: _____ CUSIP*: _________

* Preliminary, subject to change.

† CUSIP® is a registered trademark of the American Bankers Association. CUSIP data herein are provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of the American Bankers Association. CUSIP numbers have been assigned by an independent company not affiliated with the Authority and are included solely for the convenience of the holders of the 2024-1 Bonds. None of the Authority, its Municipal Advisor or the Underwriters is responsible for the selection or use of these CUSIP numbers and no representation is made as to their correctness on the 2024-1 Bonds or as indicated above. The CUSIP number for a specific bond is subject to being changed after the issuance of the bonds as a result of various subsequent actions including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of such bonds.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

BOARD OF DIRECTORS

Dukku Lee (Anaheim)
Tikan Singh (Azusa)
Jim Steffens (Banning)
Joseph Lillio (Burbank)
Robert Lopez (Cerritos)
Charles Berry (Colton)
Mark Young (Glendale)
Jamie L. Asbury (Imperial)
Martin L. Adams (Los Angeles)
David Reyes (Pasadena)
[Todd Corbin] (Riverside)
Todd Dusenberry (Vernon)

MANAGEMENT

Tikan Singh – *President*
Todd Dusenberry – *First Vice President*
Dukku Lee – *Second Vice President*
Martin L. Adams – *Secretary*
Peter Huynh – *Assistant Secretary*
Randolph R. Krager – *Interim Executive Director, Treasurer/Auditor and Assistant Secretary*
Aileen Ma – *Chief Financial and Administrative Officer*
Christine Godinez, Esq. – *General Counsel*

PROJECT PARTICIPANTS

Department of Water and Power of The City of Los Angeles
City of Burbank
City of Glendale

MUNICIPAL ADVISOR

PFM Financial Advisors LLC
Los Angeles, California

BOND COUNSEL AND DISCLOSURE COUNSEL

Norton Rose Fulbright US LLP
Los Angeles, California

SPECIAL TAX COUNSEL

Nixon Peabody LLP
Los Angeles, California

TRUSTEE AND PAYING AGENT

U.S. Bank Trust Company, National Association
Los Angeles, California

No dealer, broker, salesperson or other person has been authorized by the Authority or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Authority or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 2024-1 Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

This Official Statement is not to be construed as a contract with the purchasers of the 2024-1 Bonds. Statements contained in this Official Statement that involve estimates, forecasts or matters of opinion, whether or not expressly described herein, are intended solely as such and are not to be construed as representations of fact.

The information set forth herein has been furnished by the Authority and certain of the Project Participants, and includes information obtained from other sources which are believed to be reliable. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Project Participant since the date hereof.

The Underwriters have provided the following two paragraphs for inclusion in this Official Statement:

The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

IN CONNECTION WITH THE OFFERING OF THE 2024-1 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICES OF THE 2024-1 BONDS AT LEVELS ABOVE THOSE WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

Certain statements included or incorporated by reference in this Official Statement constitute "forward-looking statements." Such statements are generally identifiable by the terminology used such as "plan," "project," "expect," "anticipate," "intend," "believe," "estimate," "budget" or other similar words. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements described to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. The Authority does not plan to issue any updates or revisions to those forward-looking statements if or when its expectations or events, conditions or circumstances on which such statements are based occur or fail to occur.

This Official Statement, including any supplement or amendment hereto, is intended to be filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Market Access (EMMA) website. The Authority also maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2024-1 Bonds.

References to website addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader's convenience. Unless specified otherwise, such websites and the information or links contained therein are not incorporated into, and are not part of, this Official Statement for purposes of, and as that term is defined in, SEC Rule 15c2-12.

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(Continued)

Official Statement
relating to

$[PAR AMOUNT][*]

Southern California Public Power Authority

(a public entity organized under the laws of the State of California)

Southern Transmission System Renewal Project, Revenue Bonds, 2024-1

INTRODUCTION

Purpose; Authority for Issuance

This Official Statement (which includes the cover page, the table of contents and the appendices attached hereto) is furnished by the Southern California Public Power Authority (the "Authority"), a joint powers agency and a public entity organized under the laws of the State of California, to provide information concerning the Southern Transmission System Renewal Project described herein and the $[PAR AMOUNT][*] aggregate principal amount of the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 (the "2024-1 Bonds"). The 2024-1 Bonds are being issued pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the "Act") and pursuant to an Indenture of Trust, dated as of April 1, 2023 (the "Indenture of Trust"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"), as previously supplemented and as supplemented by the Third Supplemental Indenture of Trust, dated as of May 1, 2024, from the Authority to the Trustee (the "Third Supplemental Indenture"). Such Indenture of Trust, as so supplemented, is herein referred to as the "Indenture."

The 2024-1 Bonds are being issued to (i) finance a portion of the costs of acquisition and construction of capital improvements to the Southern Transmission System, an approximately 488-mile power transmission line and related facilities, which constitute part of the Intermountain Power Project (such improvements are part of the "Project" and part of the "Southern Transmission System Renewal Project," all as further described herein), (ii) fund capitalized interest on the 2024-1 Bonds and (iii) pay costs of issuance relating to the 2024-1 Bonds. See "ESTIMATED SOURCES AND USES OF FUNDS" and "SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT" herein. *The Southern Transmission System Renewal Project is to be distinguished from the Authority's existing Southern Transmission Project.*

Background; Development of the Southern Transmission System and Related Contracts

The Existing Southern Transmission System and Intermountain Power Project

The Southern Transmission System was developed in conjunction with the Intermountain Power Project (hereinafter, the "IPP"). The IPP was acquired and constructed by the Intermountain Power Agency, a political subdivision of the State of Utah ("IPA"). The IPP currently consists of: (a) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW, and a switchyard located near Delta, Utah; (b) the Southern Transmission System (described below); (c) two 50-mile 345-kV AC transmission lines from such switchyard to the Mona switchyard near Mona, Utah and a 144-mile 230-kV AC transmission line from such switchyard to the Gonder switchyard near Ely, Nevada; (d) a railcar

[*] Preliminary, subject to change.

service center; and (e) certain water rights and coal supplies. See “INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT –INTERMOUNTAIN POWER PROJECT” in Appendix B hereto for a more detailed description of the IPP.

The Southern Transmission System is a high-voltage direct current electrical transmission line running from the IPP generation station and switchyard to the Adelanto Converter Station in Adelanto, California, and is approximately 488 miles in length. The Southern Transmission System commenced commercial operations in July 1986. The Southern Transmission System includes a +500-kV DC bi-pole transmission line and an AC/DC converter station at each end and related microwave communication system facilities. Construction to upgrade the two AC/DC converter stations and increase their combined rating was completed in May 2011. The capacity of the Southern Transmission System is currently 2,400 MW.

Under a Construction Management and Operating Agreement (as amended, the “Construction Management and Operating Agreement”), participants in IPP have designated LADWP as Project Manager and Operating Agent for IPP, including the Southern Transmission System Renewal Project.

Contracts and Parties Related to the Existing Southern Transmission System and Intermountain Power Project

IPA has sold the entire capability of the IPP through June 15, 2027 to 35 entities pursuant to separate power sales contracts (the “Original Power Sales Contracts”) between IPA and each power purchaser. The IPP power purchasers include the Department of Water and Power of The City of Los Angeles (“LADWP”), and the California cities of Anaheim, Burbank, Glendale, Pasadena and Riverside. Under their respective Original Power Sales Contracts, each of the California purchasers receives certain entitlements to the use of the transmission capacity of the Southern Transmission System. LADWP and California cities of Anaheim, Burbank, Glendale, Pasadena and Riverside are hereinafter referred to as the “Original Transmission Service Purchasers.”

Pursuant to the Southern Transmission System Agreement dated as of May 1, 1983 (the “Original STS Agreement”), by and between IPA and the Authority, the Authority agreed to make payments-in-aid of construction to fund the costs of initially constructing and installing the existing Southern Transmission System and, following a first amendment to the Original STS Agreement, the costs of the construction of later additions and improvements to and renewals (including those described above) of the existing Southern Transmission System (such project is referred to herein as the Authority’s existing “Southern Transmission Project”).

The Authority has previously financed and refinanced a portion of the Southern Transmission Project through issuance of its bonds (the “Existing STS Bonds”). In connection therewith, each of the Original Transmission Service Purchasers assigned its entitlement to the transmission capacity of the Southern Transmission System to the Authority and entered into certain transmission service contracts (the “Original Transmission Service Contracts”) between the Authority and each of the Original Transmission Service Purchasers for their respective share of the use of such transmission capacity. The Existing STS Bonds are payable from and secured primarily by payments made by the Original Transmission Service Purchasers under the Original Transmission Service Contracts.

In addition to their participation in the IPP, LADWP and the California city of Burbank are among the project participants in the Authority’s Milford Wind Corridor Phase I Project (the “Milford Phase I Project”) and utilize their capacity rights to receive energy delivered from the Milford Phase I Project over the Southern Transmission System to the Adelanto Converter Station. Additionally, LADWP and the California city of Glendale are also project participants in the Authority’s Milford Wind Corridor

Phase II Project (the "Milford Phase II Project") and utilize their capacity rights to receive energy delivered from the Milford Phase II Project over the Southern Transmission System to the Adelanto Converter Station. See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Bond–Financed Projects of the Authority – *Milford Wind Corridor Phase I Project*" and "– *Milford Wind Corridor Phase II Project*."

LADWP acts as project manager and operating agent of the IPP, and is responsible for, among other things, administering, operating and maintaining the IPP.

Further Development of the Intermountain Power Project and the Southern Transmission System

Further development of the IPP and the Southern Transmission System is underway and proposed. IPA is undertaking the replacement of the coal-fired generation facilities of the IPP with natural gas-fired combustion turbine generating units capable of utilizing hydrogen for 840 MW net generation output, heat recovery steam generators and steam turbines and related facilities (the "IPP Repowering Project"). IPP plans to use renewable energy-powered electrolysis to split water into oxygen and hydrogen, storing the latter in underground salt caverns for use as fuel to drive the new electricity-generating turbines. The new natural gas generating units will be designed to utilize 30% hydrogen fuel at start-up, transitioning to 100% hydrogen fuel by 2045 as technology improves. IPA released a request for proposals in June 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with clean hydrogen fuel (i.e., hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% clean hydrogen starting in 2025 and the subsequent goal of reaching 100% clean hydrogen-fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. The request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was established in early 2022 securing energy conversion and storage services. This contract will provide the ability to convert renewable energy into clean hydrogen to fuel the new generating units in 2025.

The new generating units will be located at the site of the existing generation facilities near Delta, in Millard County, Utah. The new generation facilities are currently scheduled to enter service by July 1, 2025. See also "THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE – THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – Intermountain Power Project – Intermountain Generating Station upon the Termination of the IPP Contract" in Appendix A hereto with respect to planned replacement of the IPP coal-fired units with combined cycle natural gas-fired units.

Construction and installation of major additions and improvements to, and renewals of, the Southern Transmission System to extend its useful life are contemplated in connection with the IPP Repowering Project (such additions, improvements and renewals, as they may be modified and amended from time to time, are referred to herein as the "Southern Transmission System Renewal Project").

The Southern Transmission System Renewal Project initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment, as further described below. The new converter stations will include new HVDC converter buildings; new HVDC converter equipment, including thyristor valves, cooling equipment, AC filters, converter transformers, smoothing reactors, and protection and control systems; new DC switchyards, including DC filters and neutral bus breakers; and other work such as site preparation and grounding. The AC switchyard expansion at the Adelanto Converter Station and the Intermountain Converter Station will include additional bays for the new converter stations and the associated protections and controls for those bay positions. Additional AC system support and reactive power support in the form of new synchronous condensers will be installed at Intermountain Converter Station due to the reduction from 1,800 MW of coal-fueled to 840 MW of natural gas-fueled generation. All such additions and improvements to, and renewals of, the Southern Transmission System are referred to herein as the "Project." Estimated project costs increased and the final in-service date was extended since the April 2023 estimate primarily due to a change in scope requested by LADWP and the cities of Burbank and Glendale to upgrade the capacity of portions of the converter stations to 3,000 MW. The current cost estimate for the Project is approximately $2.66 billion. Components of the Project are currently scheduled to enter service from May 2024 through April 2028.

As described above, the components of the Project comprise the initial additions, improvements and renewals that constitute the Southern Transmission System Renewal Project, which may, in the future, be expanded to include other capital improvements to the Southern Transmission System. See "THE SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT." Additional capital improvements to the Southern Transmission System may be approved and added to the Southern Transmission System Renewal Project in the future and financed with Bonds.

IPA and each of the parties to the Original Power Sales Contracts have authorized the Project.

Contracts Related to the Southern Transmission System Renewal Project

The Project was also authorized under the Renewal Power Sales Contracts (collectively, the "Renewal Power Sales Contracts"), between IPA and each of the LADWP and the California cities of Burbank and Glendale (hereinafter collectively referred to as the "Project Participants") and certain suppliers of electric energy (collectively with the Project Participants, the "Renewal IPP Purchasers").

The Renewal Power Sales Contracts provided a process to subscribe for entitlements to the IPP Repowering Project effective when entitlement rights end under the Original Power Sales Contracts, which are scheduled to end in June 2027. Under the respective Renewal Power Sales Contracts, the Project Participants receive certain entitlements to the use of the transmission capabilities of the Southern Transmission System Renewal Project for the period beginning on the Transition Date (described below, and corresponding to the date when capacity rights under the Original Power Sales Contracts end and capacity rights become effective under the Renewal Power Sales Contracts) and ending on June 15, 2077. Each Renewal Power Sales Contract obligates the applicable Project Participant to purchase the share of the capacity and energy of the IPP (including transmission capacity of the Southern Transmission System) provided therein. The Renewal Power Sales Contracts obligate the Project Participants to pay their respective percentage shares of the costs of the IPP on a "take-or-pay" basis.

The Renewal Power Sales Contracts provide that the Project Participants, or an entity on their behalf, may make payments-in-aid of construction for the Southern Transmission System Renewal Project. To the extent that payments-in-aid of construction are made and applied to the costs of acquisition and construction of capital improvements to the Southern Transmission System Renewal Project, and IPA is not required to issue its bonds, notes or other evidences of indebtedness for such purpose, the Project Participants' payment obligations under their respective Renewal Power Sales Contracts are reduced. The terms of all of the Renewal Transmission Service Contracts is scheduled to expire on June 15, 2077 or such later date as all bonds issued by the Authority or IPA to finance the Southern Transmission System Renewal Project and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made. See "SUMMARIES OF CERTAIN DOCUMENTS – RENEWAL POWER SALES CONTRACTS" in Appendix C hereto.

The funding of the Project is described in two agreements that contemplate payments-in-aid of construction by the Authority. The financing of the Project with the Authority's Bonds is contemplated by a Second Amendment to Southern Transmission System Agreement, dated as of March 1, 2023, between IPA and the Authority, further amending the Original STS Agreement as previously amended (as so further amended, the "Existing Southern Transmission System Agreement"). The Authority's Bond financing of the Project and other costs of capital improvements to the Southern Transmission System (defined as "Capital Improvement Acquisition and Construction Costs"), which could include costs to complete the Project, is contemplated under the Renewal Southern Transmission System Agreement, dated March 1, 2023 (the "Renewal Southern Transmission System Agreement"), between IPA and the Authority. Before the Transition Date funding for the Project and Capital Improvement Acquisition and Construction Costs will be provided through payments-in-aid of construction made by the Authority under the Existing Southern Transmission System Agreement, and after the Transition Date, under the Renewal Southern Transmission System Agreement. The proceeds of the 2024-1 Bonds will fund payments-in-aid of construction for a portion of the Project. See "SUMMARIES OF CERTAIN DOCUMENTS – RENEWAL SOUTHERN TRANSMISSION SYSTEM AGREEMENT" in Appendix C hereto.

The Renewal Power Sales Contracts contemplate a scheduled "Transition Date" of June 16, 2027; provided, however, that if the date upon which the Original Power Sales Contracts terminate is extended because certain IPA obligations remain outstanding without adequate provision for the payment thereof, then the Transition Date shall be the date that is next succeeding the date upon which the Original Power Sales Contracts terminate in accordance with their terms. However, IPA fully defeased those obligations on October 1, 2021.

The Authority and each Project Participant have entered into a Renewal Agreement for the Acquisition of Capacity, dated as of March 1, 2023 (collectively, the "Renewal Capacity Acquisition Agreements"), pursuant to which each Project Participant has assigned certain entitlements to the capacity of the Southern Transmission System as upgraded and improved by the Southern Transmission System Renewal Project ("Authority Capacity") as set forth in its respective Renewal Power Sales Contract to the Authority in return for the Authority's agreement to make payments-in-aid of construction pursuant to the Existing Southern Transmission System Agreement and the Renewal Southern Transmission System Agreement. The assignment by the Project Participants of their capacity entitlements in the Southern Transmission System to the Authority under the Renewal Capacity Acquisition Agreements will be effective on the Transition Date.

The Authority and each Project Participant have also entered into a Renewal Transmission Service Contract (collectively, the "Renewal Transmission Service Contracts"). Under the Renewal Transmission Service Contracts, the Project Participants are entitled to transmission service utilizing Authority Capacity from and after the Transition Date to the extent of their respective Renewal Transmission Service Shares as set forth below, and the Project Participants are obligated to make payments therefor on a "take-or-pay" basis, that is, whether or not the Southern Transmission System Renewal Project or any part thereof has been completed, or the Southern Transmission System is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part.

Under the Renewal Transmission Service Contracts, each Project Participant is obligated to pay its share of certain costs, including amounts calculated to satisfy amounts required under the Indenture to be paid or deposited into any funds or accounts established by the Indenture for debt service and for any reserve requirements or other requirements for Bonds or other debt obligations issued or incurred under the Indenture. The Project Participants' obligations to pay commence on the Transition Date. Pursuant to the Renewal Transmission Service Contracts, such costs are to be billed by the Authority to the Project Participants monthly based on the estimates contained in an annual budget prepared by the Authority.

The payment obligations under the Renewal Transmission Service Contracts will constitute operating expenses of the respective Project Participants, payable solely from their respective electric system revenues. As operating expenses of their respective electric systems, the payment obligations of LADWP under its Renewal Transmission Service Contract and all other of its "take-or-pay" contract obligations are payable on parity with LADWP's electric system revenue bonds (see "THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE" in Appendix A hereto) and the payment obligations of the other Project Participants under their respective Renewal Transmission Service Contracts and all other of their "take-or-pay" contract obligations are payable prior to the payment of debt service on the revenue bonds of their electric systems.

The following table sets forth the Renewal Transmission Service Shares of each of the Project Participants with respect to Authority Capacity.

Project Participants	Renewal Transmission Service Share
Department of Water and Power of Los Angeles	90.500%
City of Burbank	4.222
City of Glendale	5.278
Total	100.000%

A failure by a Project Participant to make payments when due under its Renewal Transmission Service Contract will result in Step-Up Invoices being issued to the other Project Participants and could lead to transfer of the rights to transmission service of a defaulting Project Participant. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS – Renewal Transmission Service Contracts."

Before the Transition Date, IPA will include in its billings of monthly power costs allocated to the Southern Transmission System to the Original Transmission Service Purchasers (in proportion to their respective capacity rights in the Southern Transmission System under the Original Transmission Service Contracts) such amounts as shall be sufficient to pay to the Authority the amount of Bond debt service on or before the due date thereof, and, subject to the limitations contained in the Existing Southern Transmission System Agreement, will pay such amounts to the Authority on or before the due date thereof. Such billings will include billings for Bond debt service scheduled to be due on July 1, 2027, which are to be billed and payable to IPA prior to the June 16, 2027 Transition Date. Such amounts payable by IPA to the Authority are referred to as "Interim Revenues."

Security and Sources of Payment for the 2024-1 Bonds

The 2024-1 Bonds are special, limited obligations of the Authority payable solely from, and secured as to the payment of the principal or redemption price thereof, and interest thereon solely by, a pledge and assignment of Revenues (as defined in the Indenture) and certain other moneys as described herein, subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

Revenues under the Indenture consist primarily of payments to be made to the Authority by the Project Participants, pursuant to their respective Renewal Transmission Service Contract. Payments under the Renewal Transmission Service Contracts will support only Bond debt service that is due on or after the Transition Date (described above and expected to occur on June 16, 2027).

For the period to, but excluding, the Transition Date, Revenues will include Interim Revenues. Interim Revenues are payable by IPA solely from such amounts it receives from the Original Transmission Service Purchasers (in proportion to their respective capacity rights in the Southern Transmission System under the Original Transmission Service Contracts).

Interim Revenues and capitalized interest funded under the Indenture (including investment earnings thereon) are expected to fund all Bond debt service due before the Transition Date. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS."

The 2024-1 Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), the Project Participants or any other member of the Authority, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024-1 Bonds. The Authority has no taxing power.

The Third Supplemental Indenture provides that the 2024-1 Bonds are not "Participating Bonds" under the Indenture and will not be secured by a Participating Bonds Debt Service Reserve Account under the Indenture, and no Debt Service Reserve Account will be funded with respect to the 2024-1 Bonds.

The Authority

The Authority, the membership of which is comprised of eleven California cities and one California irrigation district, was formed pursuant to the Act and the Joint Powers Agreement, dated as of November 1, 1980 (as amended, the "Joint Powers Agreement"). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Formation" herein. Certain duties and responsibilities of the Authority arising in connection with the Southern Transmission System are and will be performed by LADWP pursuant to the Renewal Agency Agreement, dated as of March 1, 2023 (the "Renewal Agency Agreement"). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Organization and Management."

Outstanding and Additional Bonds and Other Obligations

Upon the issuance of the 2024-1 Bonds, there will be outstanding $[_____] principal amount of the Authority's Southern Transmission System Renewal Project revenue bonds which are payable from Revenues on parity with the 2024-1 Bonds. The Authority has reserved its right to issue additional parity bonds under the Indenture and to enter into Parity Swaps on the terms and conditions and for the purposes stated in the Indenture. The 2024-1 Bonds and any other bonds, notes or other evidence of indebtedness hereafter issued pursuant to the Act and the Indenture on a parity with the 2024-1 Bonds are herein collectively referred to as the "Bonds."

The Authority currently expects to undertake additional issuances of Bonds in [2025 and 2026] to complete the financing of the Project.

Continuing Disclosure Undertaking

Pursuant to a resolution of the Authority's Board of Directors adopted on April 18, 2024 (the "Continuing Disclosure Resolution"), the Authority has agreed for the benefit of the registered owner and the "Beneficial Owners" (as defined in the Continuing Disclosure Resolution) of the 2024-1 Bonds to provide certain financial information and operating data and to provide notices of certain events. See "CONTINUING DISCLOSURE UNDERTAKING FOR THE 2024-1 BONDS."

Certain Information; Summaries and References to Documents

In preparing this Official Statement, the Authority has relied upon information relating to the Southern Transmission System Renewal Project provided to the Authority by LADWP and information relating to certain of the Project Participants furnished to the Authority by such Project Participants. This Official Statement also includes summaries of the terms of the 2024-1 Bonds, the Indenture, the Renewal Transmission Service Contracts, the Existing Southern Transmission System Agreement, the Renewal Southern Transmission System Agreement, the Renewal Power Sales Contracts, the Renewal Capacity Acquisition Agreements, and certain other contracts and arrangements. The summaries of and references to all documents, contracts, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, report or instrument. Capitalized terms not defined herein shall have the meanings set forth in the respective documents.

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ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds relating to the 2024-1 Bonds are shown below:

Sources:	
Principal Amount	$
Bond Premium	
Total Sources	$
Uses:	
Deposit to Project Account[(1)]	$
Deposit to 2024-1 Capitalized Interest Account[(2)]	
Costs of Issuance[(3)]	
Total Uses	$

(1) Will be applied to initial costs of acquisition and construction of the Project. Total Project costs are currently expected to be approximately $2.66 billion. See "SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT" herein.

(2) Represents capitalized interest. The Authority expects such amount, together with investment earnings thereon, will fund a portion of interest payments on the 2024-1 Bonds through ____ 1, 20__, correspondingly reducing reliance on Interim Revenues to fund interest due on the 2024-1 Bonds before the Transition Date. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS" herein.

(3) Includes, among other things, Underwriters' discount, Trustee fees, Bond Counsel and Disclosure Counsel fees, Special Tax Counsel fees, rating agency fees, Municipal Advisor fees, printing costs and other miscellaneous expenses.

ESTIMATED DEBT SERVICE REQUIREMENTS

The estimated debt service requirements for the 2024-1 Bonds are set forth in Appendix F.

DESCRIPTION OF THE 2024-1 BONDS

General

The 2024-1 Bonds will be issued in fully registered form in authorized denominations of $5,000 principal amount or any integral multiple thereof. The 2024-1 Bonds will be issued in the aggregate principal amount indicated on the cover page of this Official Statement and will be dated their date of delivery. The 2024-1 Bonds will bear interest at the rates per annum and will mature on July 1 in the years and in the principal amounts set forth on the inside cover page of this Official Statement. Interest on the 2024-1 Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2024 (each, an "Interest Payment Date"). Interest on each 2024-1 Bond shall be payable to the registered owner as shown on the registration books of the Authority kept by the Trustee, as bond registrar, as of the close of business on the 15th day of the calendar month immediately preceding the applicable Interest Payment Date (the "record date"), payable from the most recent Interest Payment Date next preceding the date of authentication thereof to which interest has been paid, unless the date of authentication thereof is an Interest Payment Date to which interest has been paid, in which case interest shall be paid from such Interest Payment Date, or unless the date of authentication thereof is prior to the first Interest Payment Date, in which case interest shall be paid from the dated date thereof. Interest will be calculated on the basis of a 360-day year comprised of twelve 30-day months.

The 2024-1 Bonds when initially issued will be registered in the name of Cede & Co., as registered owner and nominee of DTC. So long as DTC, or its nominee Cede & Co., is the registered owner of all the 2024-1 Bonds, all payments of principal of and premium, if any, and interest on 2024-1 Bonds will be made directly to DTC. Disbursement of such payments to the DTC participants will be the responsibility of DTC. Disbursement of such payments to the applicable Beneficial Owners of the

2024-1 Bonds will be the responsibility of the DTC participants as more fully described herein. See "BOOK-ENTRY ONLY SYSTEM."

Redemption

Optional Redemption. The 2024-1 Bonds maturing on and after July 1, 20__ are subject to redemption prior to maturity, at the option of the Authority, from any source of available funds, in whole or in part (and, if in part, from such maturities as the Authority shall direct), on any date on or after July 1, 20__, at a redemption price equal to the principal amount of the 2024-1 Bonds, or portions thereof, to be redeemed, without premium, in each case together with accrued interest to the redemption date.

Mandatory Sinking Fund Redemption. The 2024-1 Bonds maturing on July 1, 20__ and July 1, 20__ are subject to redemption prior to maturity from mandatory sinking fund installments due on July 1 of each of the years set forth in the following tables in the respective redemption amounts set forth opposite such years in said tables, at a Redemption Price equal to the principal amount of the 2024-1 Bonds to be redeemed (together with accrued interest thereon), without premium:

2024-1 Bonds
Maturing on July 1, 20__

Redemption Date (July 1)	Redemption Amount
	$
†	

† Maturity

2024-1 Bonds
Maturing on July 1, 20__

Redemption Date (July 1)	Redemption Amount
	$
†	

† Maturity

In connection with any optional redemption of any 2024-1 Bonds that are term bonds, the principal amount of such 2024-1 Bonds being redeemed shall be allocated against the scheduled sinking fund redemption amounts set forth above in such manner as the Authority may direct and the scheduled sinking fund installments payable thereafter shall be modified as to such 2024-1 Bonds. In such event, the Authority shall provide to the Trustee a revised schedule of sinking fund installments.

Selection of 2024-1 Bonds to be Redeemed. Whenever by the terms of the Indenture, 2024-1 Bonds are to be redeemed at the direction of the Authority, the Authority shall select the maturity or maturities of 2024-1 Bonds to be redeemed. If less than all of the 2024-1 Bonds of a maturity are called for prior redemption, the particular 2024-1 Bonds or portions of such maturity to be redeemed shall be selected by lot; provided, however, that the portion of any 2024-1 Bond of a denomination of more than $5,000 to be redeemed shall be in the principal amount of $5,000 or an integral multiple thereof, and in selecting portions of such 2024-1 Bonds for redemption, the Trustee shall treat each such 2024-1 Bond as representing that number of 2024-1 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such 2024-1 Bonds to be redeemed in part by $5,000.

Notice of Redemption. The Indenture requires the Trustee to give notice of any redemption of the 2024-1 Bonds to the Owners of the 2024-1 Bonds designated for redemption by mail not less than 20 nor more than 60 days prior to the redemption date. If by the date of mailing of notice of any optional redemption the Authority has not deposited with the Trustee moneys sufficient to redeem all the 2024-1 Bonds called for redemption, such notice will state that it is subject to the availability of funds for such purpose and will be of no effect unless funds sufficient for such purpose are available on the applicable redemption date. Failure by any one or more of the Owners of any of the 2024-1 Bonds designated for redemption to receive notice of redemption or any defect in any such notice will not affect the validity of the proceedings for the redemption of any such 2024-1 Bonds.

Effect of Redemption. Notice having been given in the manner provided in the Indenture, and moneys sufficient therefor having been deposited by the Authority with the Trustee, the 2024-1 Bonds or portions thereof so called for redemption shall become due and payable on the redemption date so designated at the redemption price, plus interest accrued and unpaid to the redemption date, and, upon presentation and surrender thereof at the office specified in such notice, such 2024-1 Bonds or portions thereof, shall be paid at the redemption price, plus interest accrued and unpaid to the redemption date. If, on the redemption date, moneys for the redemption of all the 2024-1 Bonds or portions thereof to be redeemed, together with interest to the redemption date, shall be held by the Trustee so as to be available therefor on said date and if notice of redemption shall have been given as aforesaid, then, from and after the redemption date interest on the 2024-1 Bonds or portions thereof so called for redemption shall cease to accrue and shall become payable. If said moneys shall not be so available on the redemption date, such 2024-1 Bonds or portions thereof shall continue to bear interest.

BOOK-ENTRY ONLY SYSTEM

General

DTC will act as securities depository for the 2024-1 Bonds. The 2024-1 Bonds will be issued as fully registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered 2024-1 Bond certificate will be issued for each maturity of the 2024-1 Bonds in the aggregate principal amount of such maturity, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to DTC's participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com. The information on such website is not incorporated herein by reference.

Purchases of the 2024-1 Bonds under the DTC book-entry system must be made by or through Direct Participants, which will receive a credit for the 2024-1 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2024-1 Bonds ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2024-1 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2024-1 Bonds, except in the event that use of the book-entry system for the 2024-1 Bonds is discontinued.

To facilitate subsequent transfers, all 2024-1 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of 2024-1 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2024-1 Bonds. DTC's records reflect only the identity of the Direct Participants to whose accounts such 2024-1 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of the 2024-1 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2024-1 Bonds, such as redemptions, defaults and proposed amendments to the Indenture. For example, Beneficial Owners of 2024-1 Bonds may wish to ascertain that the nominee holding the 2024-1 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the Bond Registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of a maturity of the 2024-1 Bonds of an issue are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to 2024-1 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Authority as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts 2024-1 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal, redemption price and interest payments on the 2024-1 Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Authority or the Trustee, on each payment date in accordance with their respective holdings shown on DTC's records. Payments by Direct and Indirect Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such participant and not of DTC, the Trustee or the Authority, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal, redemption price and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Authority or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to Beneficial Owners is the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2024-1 Bonds at any time by giving reasonable notice to the Authority or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, the 2024-1 Bonds certificates are required to be printed and delivered.

The Authority may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, the 2024-1 Bonds certificates will be printed and delivered.

The foregoing description concerning DTC and DTC's book-entry system is based solely on information furnished by DTC. No representation is made herein by the Authority or the Underwriters as to the accuracy or completeness of such information, and the Authority and the Underwriters take no responsibility for the accuracy or completeness thereof.

Discontinuation of the Book-Entry Only System

If DTC determines not to continue to act as securities depository by giving notice to the Authority and the Trustee, and discharges its responsibilities with respect thereto under applicable law and there is not a successor securities depository, or the Authority determines not to continue the book-entry system through a securities depository, the Authority and the Trustee will cause the delivery of definitive 2024-1 Bonds to the Beneficial Owners of the 2024-1 Bonds registered in the names of such Beneficial Owners as shall be specified to the Trustee by DTC or the DTC participants.

If the book-entry system is discontinued the following provisions would apply: (i) the principal and redemption price of the 2024-1 Bonds will be payable upon surrender of any such 2024-1 Bond at the principal corporate trust office of the Trustee (as paying agent for the 2024-1 Bonds) and at the office of any other paying agent hereafter appointed by the Authority; (ii) interest on the 2024-1 Bonds will be payable by check of the Trustee mailed by first-class mail, postage prepaid, on the applicable interest payment date to the Owner thereof at their respective addresses shown on the registration books maintained by the Trustee as of the 15th day of the calendar month immediately preceding such interest payment date (the "Record Date") or in immediately available funds by wire transfer on the interest payment date to a designated account, if payable to any Owner of a 2024-1 Bond or Bonds of an issue in an aggregate principal amount of $1,000,000 or more, upon written request of such Owner to the Trustee received by the Trustee prior to the Record Date for the first interest payment date as to which such request shall be effective, specifying the account or accounts to which such payment shall be made (which request shall remain in effect until revoked or reversed by such Owner in a subsequent writing delivered to the Trustee); (iii) the transfer of any 2024-1 Bond shall be registrable only upon the books of the Authority, which shall be kept for such purposes at the principal corporate trust office of the Trustee, as bond registrar, by the Owner thereof in person or by his or her attorney duly authorized in writing, upon surrender of such 2024-1 Bond, together with a written instrument of transfer satisfactory to the bond registrar duly executed by the Owner or his or her duly authorized attorney, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such registration of transfer; (iv) 2024-1 Bonds may be exchanged for an equal aggregate principal amount of 2024-1 Bonds of the same issue, Series, tenor, maturity and interest rate in such other authorized denomination or denominations as shall be requested by such Owner, upon surrender of such 2024-1 Bonds at the principal corporate trust office of the Trustee, as bond registrar, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange; and (v) the Trustee (as bond registrar for the 2024-1 Bonds) will not be required to register the transfer of, or exchange, any 2024-1 Bonds called for redemption, or any 2024-1 Bonds during the period of 15 days next preceding any selection of 2024-1 Bonds to be redeemed.

SECURITY AND SOURCES OF PAYMENT FOR THE 2024-1 BONDS

Pledge Effected by the Indenture

The Indenture provides that the 2024-1 Bonds and any other Bonds issued thereunder shall be special, limited obligations of the Authority payable solely from and secured, as to payment of the principal or Redemption Price thereof, and interest thereon, solely by (i) the proceeds of the sale of the Bonds, including the 2024-1 Bonds, (ii) the Revenues, and (iii) all amounts on deposit in any Fund or Account established by the Indenture (except for such Funds and Accounts that the Indenture provides are not a source of payment for the Bonds or any Parity Swaps and other than any moneys held by the Trustee or the Authority to pay any rebate amount owed to the federal government) including the investments, if any, thereof, and the same are pledged and assigned pursuant to the Indenture, subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture, as security for the payment of the Bonds, the interest thereon, and premium, if any, with respect thereto, as security for the payment obligations of the Authority under any Parity Swaps and as security for the performance of any other obligations of the Authority under the Indenture, all in accordance with the provisions of the Bonds, the Indenture and any Parity Swaps.

Revenues under the Indenture consist primarily of payments to be made to the Authority by the Project Participants, pursuant to their respective Renewal Transmission Service Contracts. See " – Renewal Transmission Service Contracts" below. Payments under the Renewal Transmission Service Contracts will be available to pay only that Bond debt service that is due on or after the Transition Date (expected to occur on June 16, 2027). See "INTRODUCTION – Contracts Related to Development of the Southern Transmission System" herein. Revenues also include Interim Revenues (as defined below) during the period to, but excluding, the Transition Date. Interim Revenues and capitalized interest funded under the Indenture (including investment earnings thereon) are expected to fund all Bond debt service that is due prior to the Transition Date.

"Revenues" under the Indenture are: (A)(i) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to Authority Capacity (the rights to which have been assigned effective on the Transition Date by the Project Participants to the Authority under the Renewal Capacity Acquisition Agreements) or to the payment of the costs thereof received or to be received by the

Authority or the Trustee under the Renewal Transmission Service Contracts or under any other contract for the sale by the Authority of Authority Capacity or any part thereof or any contractual or other arrangement with respect to the use of Authority Capacity or any portion thereof or the services or capability thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to Authority Capacity, and (iii) interest received or to be received on any moneys or securities held pursuant to this Indenture and required to be paid into the Revenue Fund and (B) all Interim Revenues; but excluding (W) interest and other investment income received or to be received on any moneys or securities held pursuant to an indenture of trust entered into by the Authority with respect to bonds, notes or other evidences of indebtedness payable on a basis subordinate to the Bonds except to the extent that the Authority specifies that such interest and other investment income shall constitute Revenues, (X) amounts received by or on behalf of the Authority pursuant to any interest rate swap agreement or interest rate cap agreement relating to this Indenture except to the extent that the Authority specifies that such amounts shall constitute Revenues, (Y) amounts received by or on behalf of the Authority pursuant to a Letter of Credit relating to this Indenture except to the extent that the Authority specifies that such amounts shall constitute Revenues, and (Z) amounts on deposit in the Rebate Fund. Revenues shall not include any Subsidy Payment received by the Authority, which Subsidy Payment shall be applied as provided in the Supplemental Indenture relating to the Series of Bonds for which such Subsidy Payment is received.

Interim Revenues means all revenues of the Authority under the Interim Revenues Provision (a specified provision under the Existing Southern Transmission System Agreement). Interim Revenues will not be available to pay debt service due on and after the Transition Date. The Interim Revenues Provision provides that, prior to the Transition Date, amounts equal to the debt service on all bonds (including the 2024-1 Bonds), notes or other evidences of indebtedness issued by Authority to finance acquisition and construction costs allocable to the Project shall be payable by IPA to the Authority, and in turn billed to, and payable by, each Original Transmission Service Purchaser pursuant to its Original Power Sales Contract in proportion to its respective capacity rights in the Southern Transmission System under the Original Transmission Service Contracts. In furtherance of the foregoing, on or before the date of issuance of the 2024-1 Bonds, the Authority will submit to IPA a budget reflecting such debt service (including each payment due as part of such debt service and the due date for each such payment) for the period commencing on the date of issuance and ending on the day prior to the Transition Date. The Authority will also provide to IPA a billing for each such debt service payment due during such period at least twenty (20) days prior to the due date for such debt service payment. Based upon such budgets and billings, prior to the Transition Date, IPA will include in its billings of monthly power costs allocated to the Southern Transmission System to the Original Transmission Service Purchasers (in proportion to their respective capacity rights in the Southern Transmission System under the Original Transmission Service Contracts) such amounts as shall be sufficient to pay to the Authority the amount of such debt service on or before the due date thereof, and, subject to the limitations contained in the Existing Southern Transmission System Agreement, will pay such amounts to the Authority on or before the due date thereof. Without limiting the foregoing, IPA's foregoing obligation to pay the Authority amounts billed by the Authority are special limited obligations payable solely from amounts IPA receives from the Original Transmission Service Purchasers for such purpose. The obligations of Original Transmission Service Purchasers pursuant to the Original Power Sales Contracts to pay such bills from IPA constitute operating expenses of the respective Original Transmission Service Purchasers, payable solely from their respective electric system revenues. As operating expenses of their respective electric systems, such payment obligations of LADWP and all other of its "take or pay" contract obligations are payable on parity with LADWP's electric system revenue bonds (see "THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE" in Appendix A hereto) and such payment obligations of the other Original Transmission Service Purchasers and all other of their "take or pay" contract obligations are payable prior to the payment of debt service on the revenue bonds of their electric systems.

The following table sets forth the proportionate shares of each of the Original Transmission Service Purchasers with respect to the billings described above.

Original Transmission Service Purchasers	Share
Department of Water and Power of Los Angeles	59.534%
City of Anaheim	17.647
City of Riverside	10.164
City of Pasadena	5.883
City of Burbank	4.498
City of Glendale	2.274
Total	100.000%

A portion of the proceeds of the 2024-1 Bonds will be deposited to the 2024-1 Debt Service Account established under the Indenture on the date of delivery of the 2024-1 Bonds. The Authority expects that such amount, together with investment earnings thereon, will fund a portion of interest payments on the 2024-1 Bonds through ____ 1, 20__, correspondingly reducing reliance on Interim Revenues to fund 2024-1 Bonds interest due before the Transition Date. 2024-1 Bonds principal payments scheduled to be due before the scheduled Transition Date of June 16, 2027, if any, will be funded from Interim Revenues. 2024-1 Bonds principal and interest (net of expected capitalized interest) through the scheduled Transition Date are estimated to be $[____] million.* See "INTRODUCTION – Background; Development of the Southern Transmission System and Related Contracts – *Contracts Related to the Southern Transmission System Renewal Project*" herein.

A portion of the proceeds of the 2023-1 Bonds and the 2023-1A Bonds, on their respective issuance dates, were deposited to the related debt service accounts established under the Indenture. The Authority expects that such amounts, together with investment earnings thereon, will fund a portion of interest payments on the 2023-1 Bonds and 2023-1A Bonds, respectively, through July 1, 2027.

The 2024-1 Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), the Project Participant or any other member of the Authority, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024-1 Bonds. The 2024-1 Bonds shall not constitute the debt or indebtedness of the Authority within the meaning of any debt limitation of the Constitution or statutes of the State of California and shall not constitute nor give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power.

See "SUMMARIES OF CERTAIN DOCUMENTS – INDENTURE" in Appendix C hereto for further discussion of certain of the terms and provisions of the Indenture.

Authority Rate Covenant

Pursuant to the Indenture, the Authority has covenanted to at all times establish and collect (or cause to be collected) (i) amounts for the use of the Authority Capacity (including amounts payable under the Renewal Transmission Service Contracts) and (ii) amounts under the Interim Revenues Provision, as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of:

(1) Authority Operating Expenses during such Fiscal Year;

* Preliminary, subject to change.

(2) An amount equal to the Aggregate Debt Service (which is calculated net of capitalized interest) for such Fiscal Year;

(3) The amount, if any, to be paid during such Fiscal Year into the Participating Bonds Debt Service Reserve Account and any Series Debt Service Reserve Account;

(4) The amount, if any, to be paid during such Fiscal Year into the Reserve and Contingency Fund;

(5) The amount, if any, required to be paid into any fund or account during such Fiscal Year with respect to bonds, notes or other evidences of indebtedness payable on a basis subordinate to the Bonds;

(6) The amount, if any, required to be deposited in the General Reserve Fund during such Fiscal Year; and

(7) The amount, if any, required to pay all other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

Flow of Funds

The Indenture establishes the following Funds and Accounts (each of which is held by the Trustee): Construction Fund, Revenue Fund; Operating Fund (consisting of the Operating Account and the Operating Reserve Account); Debt Service Fund; Debt Service Reserve Fund; Reserve and Contingency Fund; and General Reserve Fund. The Construction Fund under the Indenture includes the following accounts therein: (A) the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Project Account and the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Costs of Issuance Subaccount therein as established under the Third Supplemental Indenture relating to the 2024-1 Bonds. The Debt Service Fund under the Indenture includes the following accounts therein: (A) the Participating Bonds Debt Service Account; (B) each Series Debt Service Account established pursuant to a Supplemental Indenture providing for the issuance of a Series of Bonds that are not Participating Bonds, including the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Debt Service Account therein as established under the Third Supplemental Indenture relating to the 2024-1 Bonds (the Participating Bonds Debt Service Account and each Series Debt Service Account under the Indenture being referred to under this caption as a "Debt Service Account"); and (C) each Letter of Credit Account, if any, established pursuant to a future Supplemental Indenture providing for the issuance of a Series of Bonds for which a Letter of Credit is provided. The Debt Service Reserve Fund under the Indenture includes the following accounts therein: (A) the Participating Bonds Debt Service Reserve Account; and (B) each Series Debt Service Reserve Account (if any) established pursuant to a Supplemental Indenture providing for the issuance of a Series of Bonds that are not Participating Bonds, including the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1, Debt Service Reserve Account therein (which account is not being funded in connection with the issuance of the 2024-1 Bonds) as established under the Third Supplemental Indenture relating to the 2024-1 Bonds (the Participating Bonds Debt Service Reserve Account and each Series Debt Service Reserve Account under the Indenture being referred to under this caption as a "Debt Service Reserve Account").

Pursuant to the Indenture, all Revenues received are to be deposited promptly in the Revenue Fund. Amounts in the Revenue Fund are to be paid monthly to the following Funds and Accounts in the following order of priority:

(1) To the (i) Operating Account, a sum that is equal to the total moneys appropriated for Authority Operating Expenses for deposit in the Operating Account as provided in the Annual Budget for the then current month and (ii) Operating Reserve Account, the amount required so that the amount in the Operating Reserve Account will equal the amount (if any) required to be in such Account as provided in the Annual Budget. There may be deposited in the Operating Reserve Account proceeds of Bonds or any portion thereof or moneys received in connection with the Southern Transmission System or any portion thereof from any other source, as provided in the Indenture, unless required to be applied as otherwise provided in the Indenture. Any excess amounts in the Operating Account or the Operating Reserve Account, as determined by the Authority, will be applied to make up any deficiencies in the other Funds or Accounts established pursuant to the Indenture as described therein; and thereafter any remaining excess shall be transferred to the General Reserve Fund.

(2) To the Debt Service Fund (for the ratable security and payment pursuant to clause (i) and clause (ii) of this paragraph (2) (except as otherwise provided in the Indenture and subject to the provisions thereof)), (i) (A) for credit to the Participating Bonds Debt Service Account the amount, if any, required so that the balance in said Account shall equal the Accrued Debt Service with respect to Bonds that are Participating Bonds as of the last day of the then current month, and (B) for credit to each Series Debt Service Account, the amount, if any, required so that the balance in each such Account shall equal the Accrued Debt Service with respect to the related Series of Bonds that are not Participating Bonds as of the last day of the then current month (excluding the amount, if any, set aside in such Account from the proceeds of Bonds (including amounts, if any, transferred from the Construction Fund) for the payment of interest on the related Bonds, less that amount of such proceeds to be applied in accordance with the Indenture to the payment of interest accrued and unpaid and to accrue on such related Bonds to the last day of the then current month and determining the amount of Accrued Debt Service with respect to Variable Interest Rate Bonds in accordance with the Supplemental Indenture authorizing such Variable Interest Rate Bonds) and (ii) (A) for credit to the Participating Bonds Debt Service Account, the amounts due and payable by the Authority during such month under any Parity Swap which shall be designated to the Trustee by an Authorized Authority Representative as a Parity Swap for Participating Bonds as provided in the related Supplemental Indenture or Supplemental Indentures, and (B) for credit to each Series Debt Service Account, the amounts due and payable by the Authority during such month under any Parity Swap which shall be designated to the Trustee by an Authorized Authority Representative as a Parity Swap for the related Series of Bonds as provided in the related Supplemental Indenture or Supplemental Indentures (with any termination payments under any Parity Swaps to be payable on a basis subordinate and junior to the payments to be made on the Bonds); provided, however, that, in any event, if there is a deficiency of Revenues to make all of the deposits required, such Revenues shall be deposited into each Debt Service Account on a pro rata basis based on the amounts due. The Trustee will apply amounts in the Participating Bonds Debt Service Account to the payment of principal of and interest on the Bonds that are Participating Bonds, and will apply amounts in each Series Debt Service Account to the payment of principal of and interest on the related Series of Bonds. Amounts set aside for the payment of Parity Swaps will be applied by the Trustee to any regularly-scheduled amounts due and payable by the Authority under any such Parity Swap on the due date therefor.

(3) To the Debt Service Reserve Fund, for credit to the Participating Bonds Debt Service Reserve Account and each Series Debt Service Reserve Account, the amount, if any, required to be deposited therein so that the balance in each such Account shall be equal to the requirement therefor as of the last day of the then current month; provided, however, that, in any event, if there shall be a deficiency of Revenues to make all of the deposits required, such

Revenues shall be deposited into each Debt Service Reserve Account on a pro rata basis based on the amounts due. **Pursuant to the Third Supplemental Indenture, the debt service reserve requirement for the 2024-1 Bonds shall be $0, and no Debt Service Reserve Account will be funded with respect to the 2024-1 Bonds.**

(4) To the Reserve and Contingency Fund, the amount, if any, provided for deposit therein during the then current month as provided in the Annual Budget, in accordance with written instructions from the Authority.

(5) To the General Reserve Fund, the balance, if any, in the Revenue Fund after making the above deposits.

For a more detailed discussion of the application of moneys deposited in the various funds and accounts under the Indenture, see APPENDIX C – "SUMMARIES OF CERTAIN DOCUMENTS – INDENTURE – Application of Revenues."

No Funded Debt Service Reserve Account

Pursuant to the Third Supplemental Indenture, the 2024-1 Bonds are not "Participating Bonds" under the Indenture and will not be secured by the Participating Bonds Debt Service Reserve Account created under the Indenture. **The Third Supplemental Indenture further provides that the 2024-1 Debt Service Reserve Requirement for the 2024-1 Bonds shall be $0, and therefore, no Series Debt Service Reserve Account will be funded with respect to any of the 2024-1 Bonds.**

Outstanding Bonds and Additional Bonds

Upon issuance of the 2024-1 Bonds, there will be outstanding $254,695,000 principal amount of the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2023-1 and $431,495,000 principal amount of the Authority's Southern Transmission System Renewal Project, Revenue Bonds, 2023-1A payable from Revenues on a parity with the 2024-1 Bonds. The Authority reserves the right to issue additional Bonds under the Indenture for the purposes of the Southern Transmission System Renewal Project on, and subject to, the terms and conditions set forth in the Indenture. The Authority currently expects to undertake additional issuances of Bonds in [2025 and 2026] to complete the financing of the Project. See "SOUTHERN TRANSMISSION SYSTEM."

Refunding Bonds may also be issued subject to certain terms and conditions. Such Bonds would rank equally as to security and payment with the 2024-1 Bonds and other Bonds issued under the Indenture. See "SUMMARIES OF CERTAIN DOCUMENTS – INDENTURE – Certain Requirements of and Conditions to Issuance of Bonds" and "- Refunding Bonds" in Appendix B hereto.

Annual Budget

The Renewal Transmission Service Contracts and the Indenture require the Authority to adopt an Annual Budget not less than 30 nor more than 45 days prior to the beginning of each Transmission Service Year. Each Annual Budget will incorporate therein all items comprising a part of Monthly Transmission Costs, estimated Revenues required to be collected and the estimated amount to be deposited in each month in the Funds and Accounts under the Indenture (including the amounts required (or in good faith estimated to be required) for the accrual or payment (as applicable) of Accrued Debt Service on the Bonds, the payment of Authority Operating Expenses, the funding or replenishment of any reserves (including all Accounts in the Debt Service Reserve Fund) required by the Indenture, provision for any general reserve for Authority Operating Expenses and the estimated amount to be deposited in the

Reserve and Contingency Fund (if any), and provision for any such other expenditures and deposits as the Authority shall determine shall be necessary or appropriate so as to enable the Authority to comply with the Indenture and the Renewal Transmission Project Contracts. See "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Renewal Transmission Service Contracts." If there are at any time during any Fiscal Year extraordinary receipts or payments of unusual costs with respect to the Authority Capacity, or the amount in the Debt Service Fund or the Debt Service Reserve Fund shall be less than the respective balances required by the Indenture, the Authority shall promptly adopt in accordance with the provisions of the Renewal Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year. The Authority may also at any time adopt in accordance with the provisions of the Renewal Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year.

Renewal Transmission Service Contracts

General. The Authority has entered into a Renewal Transmission Service Contract with respect to the Southern Transmission System Renewal Project with each Project Participant pursuant to which the Authority agrees to provide to such Project Participant its Renewal Transmission Service Share of transmission service utilizing the Authority Capacity from and after the Transition Date.

Term of Renewal Transmission Service Contracts. Except as provided therein, each Renewal Transmission Service Contract between the Authority and a Project Participant constitutes an obligation of the parties until the terms of all of the Renewal Transmission Service Contracts expire on June 15, 2077 or such later date as all Bonds and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made. Until all Bonds and the interest thereon shall have been paid in full or until provision has been made for such payment, the Renewal Transmission Service Contracts may not be terminated, amended, modified, or otherwise altered in any manner which will reduce the payments pledged as security for Bonds or extend the time of such payments or which will in any manner impair or adversely affect the rights or security of the holders from time to time of Bonds. Under the Renewal Transmission Service Contracts, payments by Project Participants in respect of debt service on the Bonds are required only for such debt service that is due on or after the Transition Date.

Covenant to Maintain Sufficient Rates. Each Project Participant has covenanted in its Renewal Transmission Service Contract to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves, are adequate to enable it to pay the Authority all amounts payable when due under its Renewal Transmission Service Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

"Take-or-Pay" Obligation. Payments are to be made by the Project Participants on a "take-or-pay" basis, that is, whether or not the Project or any part thereof has been completed, whether or not the Southern Transmission System is operating or operable or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

The payment obligations under the Renewal Transmission Service Contracts constitute a cost of transmission service and an operating expense of the respective Project Participants, payable solely from their electric system revenues. As operating expenses of their respective electric systems, the payment obligations of LADWP under its Renewal Transmission Service Contract and all other of its "take-or-pay" contract obligations are payable on a parity with LADWP's electric system revenue bonds, and the payment obligations of the other Project Participants under their respective Renewal Transmission

Service Contracts and all other of their "take-or-pay" contract obligations are payable prior to the payment of debt service on the revenue bonds of their electric systems.

Monthly Costs. The Renewal Transmission Service Contracts provide that the obligations of the Project Participants under the respective Renewal Transmission Service Contracts are several and not joint. During each Transmission Service Year, each Project Participant is obligated to pay its share of Monthly Transmission Costs, which consist of all of the Authority's costs resulting from the acquisition, financing and refinancing of Authority Capacity, to the extent not paid from the proceeds of the Bonds or other debt obligations (provided, however, that such costs do not include any amounts that are included or to be included in a Step-Up Invoice (described below)), as well as the amounts set forth in any Step-Up Invoice or Default Invoice submitted by the Authority to the Project Participant. The Project Participants' obligations to make payments under the Renewal Transmission Service Contracts commence on the Transition Date. Pursuant to the Renewal Transmission Service Contracts, such Monthly Transmission Costs are to be billed by the Authority to the Project Participants by the tenth calendar day of each month for the then current month based on the estimates contained in the Annual Budget prepared by the Authority prior to the beginning of each Transmission Service Year, as such Annual Budget may be amended during such year, and are to be paid by the Project Participants on or before ten days after receipt of such billing statement therefor. Such Monthly Transmission Costs include, without limitation:

(1) Monthly Power Costs (as defined in the Renewal Power Sales Contracts) allocable to the Southern Transmission System (this clause (1) referred to below as the "Monthly Power Cost component");

(2) The amount which is required under the Indenture to be paid or deposited during such Month into any funds or accounts established by the Indenture for debt service and for any reserve requirements or other requirements for Bonds or other debt obligations issued or incurred under the Indenture; provided, however, such amounts shall not include any amounts included or to be included in a Step-Up Invoice;

(3) One-twelfth of the amount (not otherwise included above) which is required under the Indenture to be paid or deposited during such Transmission Service Year into any funds or accounts established by the Indenture; and shall include, without limitation, amounts required to make up a deficiency in any such fund or account whether or not resulting from a default in payments by any Project Participant; provided, however, such amounts shall not include any amounts included or to be included in a Step-Up Invoice (clause (2) above and this clause (3) referred to below as the "Indenture cost component");

(4) One-twelfth of the costs of providing transmission service during the then current Transmission Service Year (not otherwise included above); and

(5) One-twelfth of the amount necessary during the then current Transmission Service Year to pay or provide reserves for all taxes which the Authority is required to pay with respect to Authority Capacity (not otherwise included above) (clause (4) above and this clause (5) referred to below as the "transmission cost component").

The amount of Monthly Transmission Costs to be paid by each Project Participant for any month shall be its Renewal Transmission Service Share times the Monthly Transmission Costs for such month.

Statements and Reports. Subject to the Renewal Southern Transmission System Agreement and the Renewal Power Sales Contracts, the Authority will prepare or cause to be prepared and issue to the Project Participants the following reports each calendar quarter of the Transmission Service Year:

(1) Financial and operating statements relating to the Southern Transmission System;

(2) Status of Annual Budget; and

(3) Analysis of operations relating to the Southern Transmission System.

Amendment of Annual Budget. If there are at any time during any Fiscal Year extraordinary receipts or payments of unusual costs with respect to the Authority Capacity, or the amount in the Debt Service Fund or the Debt Service Reserve Fund is less than the respective balances required by the Indenture, the Authority is required to promptly adopt in accordance with the provisions of the Renewal Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year. The Authority may also at any time adopt in accordance with the provisions of the Renewal Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year.

Reconciliation of Monthly Costs. On or before 150 days after the end of each Transmission Service Year, the Authority will submit to the Project Participants a detailed statement of the actual aggregate Monthly Transmission Costs and other amounts payable the Renewal Transmission Service Contracts, including credits thereto, for all of the Months of such Transmission Service Year, and the adjustments of the aggregate Monthly Transmission Costs and other amounts payable thereunder, if any, for any prior Transmission Service Year, based on the annual audit of accounts provided for in the Renewal Transmission Service Contracts. If the actual aggregate Monthly Transmission Costs or other amounts payable for any Transmission Service Year exceed the amount thereof which Project Participants have been billed, the Project Participants shall promptly pay to the Trustee its share of such excess. If the actual aggregate Monthly Transmission Costs or other amounts payable for any Transmission Service Year are less than the amount therefor which Project Participants have been billed, the Authority shall credit such excess to the Project Participants in accordance with its customary procedures. In the event that the failure of a Project Participant to make its payments in accordance with its Renewal Transmission Service Contract results in the application of amounts in any fund under the Indenture to the payment of costs payable from such fund and the other Project Participants shall have made up the deficiency created by such application or paid additional amounts into such fund, amounts thereafter paid to the Trustee by the failing Project Participant for application to such past due payments including interest at one and one-half percent per Month shall be credited on the Billing Statements of such other Project Participants in the next Month or Months as shall be appropriate.

Project Participant's Failure to Pay Billing Statement. In the event a Project Participant fails to pay all or a portion of its Billing Statement by the due date (a "Payment Default") and fails to cure by the earlier of five days thereafter or the last day of the then current month, the Authority will issue an invoice to the Project Participant identifying the total defaulted amount owed, including late payment interest (a "Default Invoice").

Payment Default May Affect Other Project Participants; Step-Up Invoices. If a Project Participant fails to pay its Billing Statement when due, the shortfall in Revenues will be allocated proportionately among all the non-defaulting Project Participants as and to the extent described below.

In the event of a Payment Default by one or more Project Participants, the Authority shall provide by the fifth day of the month following such Payment Default(s) a separate Step-Up Invoice to each non-defaulting Project Participant that specifies such party's pro rata share, based upon the Renewal Transmission Service Shares of all non-defaulting Project Participant, of the amount of the Payment Default(s) set forth in the Billing Statement(s) for the defaulting Project Participant (s). Notwithstanding the previous sentence, the amount of a Step-Up Invoice provided to a non-defaulting Project Participant shall not exceed 15% of the amount that such non-defaulting Project Participant was billed in its Billing Statement (excluding amounts billed under any prior Step-Up Invoice) for the Month preceding such monthly Step-Up Invoice; provided, however, that upon payment in full of all Bonds and termination of the applicable Renewal Transmission Service Contract, a non-defaulting Project Participant shall not be obligated or otherwise liable for any amounts owed by any other Project Participant.

If a Project Participant pays less than the total amount of its Step-Up Invoice, such failure constitutes a Payment Default and the Authority shall provide by the fifth day of the month following such Payment Default a separate Default Invoice to the applicable Project Participant that identifies the total defaulted amount owed, including late payment interest.

Application of Moneys Received from Step-Up Invoices. Moneys received by or on behalf of the Authority from the payment of Step-Up Invoices relating to a Payment Default of a Project Participant shall be applied in the following manner: (1) moneys received from Project Participants in respect of the Monthly Power Costs component and the transmission costs component, as set forth in the Step-Up Invoice, shall be forwarded to the Trustee for deposit into the Revenue Fund under the Indenture; and (2) moneys received from Project Participants in respect of the Indenture cost component, as set forth in the Step-Up Invoices shall, be forwarded to the Trustee for deposit directly into the Debt Service Fund under the Indenture. Any partial payment shall be applied in the following order: (i) first to the payment of the Monthly Power Costs component and transmission costs component, on a pro rata basis in the event of any deficiency, and (ii) thereafter to the payment of the Indenture cost component.

Application of Moneys Received from Default Invoices. Moneys received by or on behalf of the Authority from the payment of Default Invoices shall be applied in the following manner: (1) The Authority shall credit on each non-defaulting Project Participant's next Billing Statement an amount equal to the aggregate amount such non-defaulting Project Participant paid as a result of Step-Up Invoices with respect to such Default Invoice, plus a pro rata share, based upon the Renewal Transmission Service Shares of the non-defaulting Project Participants, of the amount the Authority received regarding late payment interest charges. In the event a Defaulting Project Participant pays less than the full amount of its Default Invoice, the credit to each non-defaulting Project Participant shall be adjusted proportionately. (2) The Authority shall forward or cause to be forwarded to the Trustee for deposit into the Revenue Fund of the Indenture moneys received with respect to the payment of Default Invoices.

Remedies; Transfer of Rights of Defaulting Project Participants. In the event of a default or inability to perform by a Project Participant under its Renewal Transmission Service Contract, the Authority shall bring any suit, action or proceeding at law or in equity as may be necessary or appropriate to enforce any covenant, agreement or obligation against the Project Participant. The Renewal Transmission Service Contracts also provide that if a payment due under a Renewal Transmission Service Contract remains unpaid when due, the Authority may, upon 90 days' written notice to the Project Participant, discontinue transmission service to such Project Participant while the default continues.

In the event of a default by a Project Participant and the discontinuance of transmission service, the Authority shall transfer on a pro rata basis to all requesting Project Participants which are not in default and pursuant to procedures established by the Board of Directors, the defaulting Project Participant's rights to transmission service which shall have been discontinued by reason of such default, and such requesting Project Participants shall assume the defaulting Project Participant's obligations with respect to such rights so transferred, and if any of the defaulting Project Participant's rights with respect to transmission service are not so transferred, the Authority shall, to the extent possible, dispose of such remaining portion on the best terms readily available; provided, however, that the Authority may not transfer or dispose of such defaulting Project Participant's rights and obligations in such a manner as shall, in the opinion of Special Tax Counsel, adversely affect the federal tax exemption for any Bonds, and provided, further, that the obligation of the defaulting Project Participant to make payments under its Renewal Transmission Service Contract including the costs to the Authority related to such default, transfer and sale, shall be reduced to the extent that payments are received as provided in the Renewal Transmission Service Contract for that portion of the defaulting Project Participant's rights with respect to transmission service which are so transferred or disposed. Except as a result of the receipt of payments due to a transfer of the defaulting Project Participant's rights to transmission service, the discontinuance of transmission service to a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Renewal Transmission Service Contract.

See "SUMMARIES OF CERTAIN DOCUMENT – RENEWAL TRANSMISSION SERVICE CONTRACTS" in Appendix C hereto for a discussion of certain additional provisions of the Renewal Transmission Service Contracts.

SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT

General Description

The Southern Transmission System constitutes one of the components of the IPP. See "INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT – INTERMOUNTAIN POWER PROJECT" in Appendix B hereto for a more detailed description of the IPP.

The Southern Transmission System currently consists of: (a) the AC/DC Intermountain Converter Station adjacent to the IPP AC switchyard; (b) the ±500-kV DC bi-pole transmission line ("HVDC transmission line"), approximately 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California; (c) the AC/DC Adelanto Converter Station, where the Southern Transmission System connects to the switching and transmission facilities of the LADWP; and (d) related microwave communication system facilities. The HVDC transmission line is designed to have the capability of transmitting in excess of the aggregate Generation Station Production anticipated to be delivered to the Project Participants. The AC/DC converter stations each consist of two solid state converter valve groups and have a combined rating of 2,400 MW. The microwave communication system facilities are used for Generation Station dispatch, for IPP communication, and for control and protection of the Southern Transmission System. The microwave system facilities are located along two routes between the Generation Station and Adelanto, forming a loop network.

The Authority's existing Southern Transmission Project was undertaken in connection with the development and financing of the existing Southern Transmission System See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Bond-Financed Projects of the Authority – Southern Transmission Project" herein.

The Project is the planned upgrade and renewal of the Southern Transmission System related to IPA's replacement of the current coal-fired generation facilities of the IPP with natural gas-fired combustion turbine generating units capable of utilizing hydrogen for 840 MW net generation output, heat recovery steam generators and steam turbines and related facilities (earlier defined as the "IPP Repowering Project"). IPP plans to use renewable energy-powered electrolysis to split water into oxygen and hydrogen, storing the latter in underground salt caverns for use as fuel to drive the new electricity-generating turbines. The new natural gas generating units will be designed to utilize 30% hydrogen fuel at start-up, transitioning to 100% hydrogen fuel by 2045 as technology improves. IPA released a request for proposals in June 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with clean hydrogen fuel (i.e., hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% clean hydrogen starting in 2025 and the subsequent goal of reaching 100% clean hydrogen-fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. The request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was established in early 2022 securing energy conversion and storage services. This contract will provide the ability to convert renewable energy into clean hydrogen to fuel the new generating units in 2025.

The new generating units will be located at the site of the existing generation facilities near Delta, in Millard County, Utah. See also "THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE – THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – Intermountain Power Project – Intermountain Generating Station upon the Termination of the IPP Contract" in Appendix A hereto.

The Project includes construction and installation of major additions and improvements to, and renewals of, the Southern Transmission System to extend its useful life. The STS Renewal Project includes new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. The new converter stations will include new HVDC converter buildings; new HVDC converter equipment, including thyristor valves, cooling equipment, AC filters, converter transformers, smoothing reactors, and protection and control systems; new DC switchyards, including DC filters and neutral bus breakers; and other work such as site preparation and grounding. The AC switchyard expansion at the Adelanto Converter Station and the Intermountain Converter Station will include additional bays for the new converter stations and the associated protections and controls for those bay positions. Additional AC system support and reactive power support in the form of new synchronous condensers will be installed at IPP due to the reduction from 1,800 MW of coal to 840 MW of natural gas-fueled generation. Estimated project costs increased and the final in-service date was extended since the April 2023 estimate primarily due to a change in scope requested by LADWP and the cities of Burbank and Glendale to upgrade the capacity of portions of the converter stations to 3,000 MW. The current cost estimate for the Project is approximately $2.66 billion. LADWP will manage improvements at the Adelanto AC switchyard. Third-party contracts have been awarded for improvements at the AC switchyard at the IPP and the converter stations in Adelanto and at the IPP, and for synchronous condensers. Construction began at the IPP AC switchyard in June 2022, the Adelanto Switchyard in July 2022, and the synchronous condenser in July 2023. The projected construction start date for the converter stations, the last remaining component, is May 2024. Components of the planned upgraded facilities are currently scheduled to enter service from May 2024 through April 2028.

Under the Construction Management and Operating Agreement, LADWP's actions and recommendations in its role as Project Manager and Operating Agent for IPP, including the Southern Transmission System Renewal Project, are subject to review, modification and approval by the IPP Coordinating Committee. LADWP is required to operate and maintain the Southern Transmission System in accordance with prudent utility practices.

Previous Upgrades and Operations

The Southern Transmission Project has operated with excellent availability and reliability. Previous upgrade projects have increased the capacity of the Southern Transmission System from 1,920 MW to 2,400 MW. The Southern Transmission System currently includes a +500-kV DC bi-pole transmission line. When one pole is out of service, the Southern Transmission Project is designed to operate in a mono-polar mode at a reduced capacity rating of 1,200 MW. Because the Southern Transmission Project is designed to operate in this manner, reliability for system planning purposes is essentially equivalent to that of two AC transmission lines.

During the fiscal year ended June 30, 2023, transmission availability (one or both poles on) was approximately 97.28%. Scheduled outages are largely controlled to occur simultaneously with scheduled generating unit outages and thus do not interfere significantly with scheduled energy deliveries.

In the fiscal year ended June 30, 2023, the Original Transmission Service Purchasers received approximately 6.6 million MWh of energy over the line, consisting of a majority from IPP and the balance from Milford Wind Corridor Phase I Project, Milford Wind Corridor Phase II and various other purchases by certain of the Original Transmission Service Purchasers.

See "INTERMOUNTAIN POWER PROJECT AND INTERMOUNTAIN POWER AGENCY – INTERMOUNTAIN POWER PROJECT – General Description" in Appendix B for additional information regarding the operations of the Southern Transmission Project.

Arrangements for Transmission Service from Adelanto Converter Station

LADWP takes delivery of its share of the IPP Generating Station entitlements at the Adelanto Converter Station. The other Original Transmission Service Purchasers also have designated the Adelanto Converter Station as their point of delivery. LADWP has constructed a station and associated facilities to connect the Adelanto Converter Station with the LADWP's main transmission system. Under separate agreements, LADWP transmits the generation entitlements of the cities of Glendale and Burbank directly to those cities' respective systems. Transmission services for the city of Pasadena to its electric system are currently provided by the LADWP and the California Independent System Operator. The California Independent System Operator also provides transmission services for the cities of Anaheim and Riverside. The rights of the Original Transmission Service Purchasers under their existing IPP agreements for the delivery of the generation entitlements over the Southern Transmission System are scheduled to terminate on June 15, 2027.

The rights of the Renewal Transmission Service Purchasers under their new IPP agreements for the delivery of the generation entitlements over the Southern Transmission System are scheduled to commence on June 16, 2027 and terminate on June 15, 2077. The Project Participants will continue to take delivery of their IPP Generation Station Entitlements at the Adelanto Converter Station. LADWP will provide transmission service for the other two Renewal Transmission Service Purchasers. LADWP will transmit the generation entitlements of the cities of Glendale and Burbank directly to those cities' respective systems.

Intermountain Power Project Fuel Supply

IPA has entered into coal supply agreements to fulfill the supply requirement of the Intermountain Generating Station of approximately [4.0] million tons per year. However, supply chain issues have dramatically reduced coal supply beginning in the later months of 2021 and are expected to impact coal supply for the remaining life of the coal plant. See "APPENDIX A - THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE - THE POWER SYSTEM - Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units - Intermountain Power Project - Fuel Supply."

Permits, Licenses and Approvals

The Southern Transmission System has been designed and constructed to operate in compliance with applicable federal, state and local regulations, codes, standards and laws. The Authority believes that all necessary permits, licenses and approvals for the Project have been or will be secured.

CERTAIN FINANCIAL STATEMENTS RELATING TO THE PROJECT

The following Statement of Net Position has been prepared by the Authority based upon audited financial statements of the Authority for the fiscal year ended June 30, 2023.

Southern California Public Power Authority
Southern Transmission System Renewal Project
Statement of Net Position
(In thousands)

	Fiscal Year Ended June 30, 2023
ASSETS	
Noncurrent assets	
Net utility plant	$215,801
Investments – restricted	469,279
Advances to IPA – restricted	4,445
Total noncurrent assets	689,525
Current assets	
Cash and cash equivalents – restricted	130,669
Cash and cash equivalents – unrestricted	-
Interest receivable	1,871
Total current assets	132,540
DEFERRED OUTFLOWS OF RESOURCES	
Total deferred outflows of resources	-
Total assets and deferred outflows of resources	$822,065
LIABILITIES	
Noncurrent liabilities	
Long-term debt	$785,311
Total noncurrent liabilities	785,311
Current liabilities	
Accrued interest	5,274
Accounts payable and accruals	31,381
Total current liabilities	36,655
Total liabilities	821,966
DEFFERED INFLOWS OF RESOURCES	
Regulatory liability	99
Total deferred inflows of resources	99
NET POSITION	
Net investment in capital assets	(437,068)
Restricted	437,068
Unrestricted	-
Total net position	-
Total liabilities, deferred inflows of resources, and net position	$822,065

THE PROJECT PARTICIPANTS

The Project Participants, each of which has executed a Renewal Capacity Acquisition Agreement and a Renewal Transmission Service Contract with the Authority, are LADWP, the City of Burbank and the City of Glendale. Each of the Project Participants owns and operates an electric system for the distribution of electric energy to its retail customers. For additional information concerning LADWP, which will have a Renewal Transmission Service Share of 90.500% for the Southern Transmission System under the Renewal Transmission Service Contracts from and after the Transition Date, and its electric system, see Appendix A hereto.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement expires in 2030 or on such later date as all bonds and notes of the Authority and interest thereon have been paid in full or adequate provision for such payment has been made in accordance with the instruments governing such bonds and notes.

Organization and Management

The Authority is governed by a Board of Directors which consists of one representative for each of the members. The current representatives are listed on the masthead page of this Official Statement. The management of the Authority is under the direction of its Interim Executive Director, Randolph R. Krager, who serves at the pleasure of the Board of Directors. Mr. Krager also serves as the Treasurer/Auditor and Senior Project Development Manager of the Authority. Prior to his appointment as Interim Executive Director of the Authority in April 2024 and appointment to Senior Project Development Manager of the Authority in 2017, Mr. Krager previously served as Senior Solar and Renewable Resource Planning and Development Manager with LADWP. Mr. Krager is a 33-year veteran of LADWP and assumed various positions such as Market Analysis Manager, Resource Planning Manager, Wholesale Marketing Trading Floor Manager, Generation Project Manager, Power Systems Emergency Operations Responder, and Technical Engineer. While employed at LADWP. Mr. Krager led teams that helped with the development and procurement of LADWP's renewable portfolio, 20-year integrated resource plan and conventional generation and transmission development. He was part of the core team that established LADWP's wholesale marketing group that successfully navigated the State of California energy crisis. Mr. Krager holds a bachelor's degree in electrical engineering from the University of California at San Diego, a master's degree in electrical engineering from San Diego State University, and a master's degree in business administration from Pepperdine University.

The other officers of the Authority are selected by the Board of Directors. The President of the Authority, since January 22, 2024, is Tikan Singh, General Manager of Azusa Light and Water. Mr. Singh is a professional engineer registered in the State of California with 14 years of utilities experience. Before joining Azusa Light and Water, he worked in various capacities at Palo Alto Utilities, Lompoc Electric Utility, and the California Department of Water Resources. The First Vice President of the Authority, since February 2024, is Todd Dusenberry, General Manager of Vernon Public Utilities. He has seventeen years of public utilities experience with the City of Vernon, previously serving as a systems coordinator, systems supervisor, utilities operations manager, utilities compliance officer, utilities compliance manager and assistant general manager. He was also a board member of the California

Utilities Emergency Association. The Second Vice President of the Authority, since February 2024, is Dukku Lee, General Manager of Anaheim Public Utilities. He has served Anaheim Public Utilities since November 1999 and was appointed as its General Manager in November 2013. He previously worked for Southern California Edison and Paragon Consulting Services.

Aileen Ma joined the Authority as Chief Financial and Administrative Officer in June 2019. Ms. Ma was previously Interim Utilities Assistant General Manager/Finance & Administration for the City of Riverside Public Utilities Department. Ms. Ma's employment at Riverside began in 2006. Prior to her appointment as Interim Utilities Assistant General Manager/Finance & Administration, she served in the positions of Utilities Principal Analyst and Utilities Fiscal Manager at Riverside. She has over 25 years of experience in audit, accounting and finance administration. Ms. Ma is a Certified Public Accountant, and holds a Bachelor of Science in Business Administration with an Accounting emphasis from California State University, Los Angeles and a Master of Business Administration from University of California, Irvine.

With respect to any matter involving the acquisition and financing or refinancing of an Authority project to be decided by the Board of Directors, each Director is entitled to cast votes weighted according to the size of the entitlement to the project of each project participant in addition to the vote each Director is entitled to cast as a member of the Authority. All such matters must be decided by at least 80% of the votes cast, and no such vote may be taken unless there shall be present at the meeting Directors entitled to cast more than 50% of the votes relative to such matter. Voting by the Board of Directors may take place at meetings of the Board of Directors when a quorum is present. A majority of the Board of Directors constitutes a quorum.

The Authority has entered into the Renewal Agency Agreement pursuant to which LADWP, as agent, represents and undertakes certain activities on behalf of the Authority in connection with the Authority's payments-in-aid of construction and the acquisition and financing or refinancing of Authority Capacity. The Renewal Agency Agreement gives the agent the responsibility of (a) undertaking those activities necessary (i) to secure regulatory approvals to allow the Authority to acquire Authority Capacity, (ii) to formulate arrangements for the transmission of Authority Capacity to the Project Participants, (iii) to formulate the financing program and develop financing documents and (iv) to acquire the Authority Capacity, and (b) representing the Authority with respect to matters arising under or in connection with the Project Agreements (as defined in the Renewal Agency Agreement) or the acquisition of Authority Capacity.

Other Bond-Financed Projects of the Authority

In addition to the Southern Transmission System Renewal Project to be financed with the 2024-1 Bonds, the following are the projects of the Authority that have been financed by bonds issued by the Authority. The principal of and premium, if any, and interest on the 2024-1 Bonds are secured solely by and payable solely from the Revenues and certain other moneys pledged therefor under the Indenture as described herein. None of the costs associated with the projects described below in this subsection is payable from such Revenues and such other moneys pledged to the payment of the Bonds.

Southern Transmission Project. *The Southern Transmission Project is to be distinguished from the Southern Transmission System Renewal Project, which is described elsewhere in this Official Statement.* The Southern Transmission System is one component of the Intermountain Power Project ("IPP," as defined herein) of IPA. Certain members of the Authority (namely, LADWP and the California cities of Anaheim, Burbank, Glendale, Pasadena and Riverside) have entered into power sales contracts with IPA pursuant to which they purchase a share of the generation and transmission capabilities of the IPP, including capacity and energy of the Intermountain Generation Station, a two-unit coal-fired, steam-electric generating plant, located in Millard County, Utah, and operating capabilities of the Southern Transmission System. The Authority acquired from each of such members its entitlement rights to capacity of the Southern Transmission System and agreed in return to issue bonds (defined above as "Existing STS Bonds"), notes or other evidences of indebtedness and make payments-in-aid of construction to IPA therefor (the "Southern Transmission Project"). All of the facilities of the IPP have been in commercial operation since May 1, 1987. The Authority has sold all of its acquired capability of the Southern Transmission System, on a "take or pay" basis, through transmission service contracts with the Original Transmission Service Purchasers. The currently operative IPP power sales contracts pursuant to which such Original Transmission Service Purchasers have obtained their rights for the delivery of the IPP generation entitlements over the Southern Transmission System, as well as the Original Transmission Service Contracts, are scheduled to terminate on June 15, 2027. The Authority had outstanding $116,535,000 aggregate principal amount of Existing STS Bonds as of April 1, 2024.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Southern Transmission System Renewal Project.

Mead-Adelanto Project, Authority Interest (Multiple Members). The Mead-Adelanto Transmission Project consists of an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. By connecting to Marketplace Substation, the line interconnects with the Mead-Phoenix Transmission Project and with the existing McCullough Substation in southern Nevada. The transmission line has a transfer capability of 1,291 MW. The current owners of the Mead-Adelanto Transmission Project are the Authority and StarTrans IO, L.L.C. The Authority has three separate and independent ownership interests in the Mead-Adelanto Project under the related joint ownership agreement: (i) one interest for the nine Authority members participating in that portion of the project acquired in connection with the original construction of the project (i.e., the Authority Interest (Multiple Members) in such project), the acquisition and construction of which was financed with revenue bonds of the Authority; (ii) one interest for Western Area Power Administration ("Western"), the funding for which is provided by Western; and (iii) an additional interest acquired by the Authority in 2016 from M-S-R Public Power Agency, for the benefit of LADWP only (i.e., the Authority Interest (LADWP Only) in such project) hereinafter described (see "– *Mead-Adelanto Project, Authority Interest (LADWP Only)*" below), the acquisition of which was financed through a separate issue of revenue bonds of the Authority issued for the benefit of LADWP only. The Authority Interest (Multiple Members) in the Mead-Adelanto Project provides to the Authority a 67.9167% member-related ownership share in the Mead-Adelanto Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (Multiple Members) in the Mead-Adelanto Project through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID, and the California cities of Cerritos and Vernon). From and after July 1, 2020, the Authority had no bonds outstanding with respect to the Authority Interest (Multiple Members) in the Mead-Adelanto Project.

Mead-Phoenix Project, Authority Interest (Multiple Members). The Mead-Phoenix Transmission Project consists of an approximately 256-mile, 500-kV alternating current ("AC") transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. The line is looped through the 500-kV switchyard constructed in the existing Mead Substation in southern Nevada with a transfer capability of 1,923 MW (as a result of upgrades completed in 2009). By connecting to Marketplace Substation, the Mead-Phoenix Transmission Project interconnects with the Mead-Adelanto Transmission Project and with the existing McCullough Substation. The current owners of the Mead-Phoenix Transmission Project are the Authority, Arizona Public Service Company, Salt River Project and StarTrans IO, L.L.C. The

Authority has three separate and independent ownership interests in the Mead-Phoenix Project under the related joint ownership agreement: (i) one interest for the nine Authority members participating in that portion of the project acquired in connection with the original construction of the project (i.e., the Authority Interest (Multiple Members) in such project), the acquisition and construction of which was financed with revenue bonds of the Authority; (ii) one interest for Western, the funding for which is provided by Western; and (iii) an additional interest acquired by the Authority in 2016 from M-S-R Public Power Agency, for the benefit of LADWP only (i.e., the Authority Interest (LADWP Only) in such project) hereinafter described (see "*– Mead-Adelanto Project, Authority Interest (LADWP Only)*" below), the acquisition of which was financed through a separate issue of revenue bonds of the Authority issued for the benefit of LADWP only. The Mead-Phoenix Transmission Project is comprised of three project components. The Authority Interest (Multiple Members) in the Mead-Phoenix Project provides to the Authority an 18.3077% member-related ownership share in the Westwing-Mead Component, a 17.7563% member-related ownership share in the Mead Substation Component, and a 22.4082% member-related ownership share in the Mead-Marketplace Component of the Mead-Phoenix Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (Multiple Members) in the Mead-Phoenix Project through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID, and the California cities of Cerritos and Vernon). From and after July 1, 2020, the Authority had no bonds outstanding with respect to the Authority Interest (Multiple Members) in the Mead-Phoenix Project.

Mead-Adelanto Project, Authority Interest (LADWP Only). In 2016, the Authority acquired, for the benefit of LADWP only, all of M-S-R Public Power Agency's ownership interest in the Mead-Adelanto Project, representing an additional 17.5000% ownership interest in the Mead-Adelanto Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (LADWP Only) in the Mead-Adelanto Project through a transmission service contract with LADWP. The Authority had outstanding $15,980,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Adelanto Project as of April 1, 2024.

Mead-Phoenix Project, Authority Interest (LADWP Only). In 2016, the Authority acquired, for the benefit of LADWP only, all of M-S-R Public Power Agency's ownership interest in the Mead-Phoenix Project, representing an additional 11.5385% ownership interest in the Westwing-Mead Component and an additional 8.0993% ownership share in the Mead-Marketplace Component of the Mead-Phoenix Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (LADWP Only) in the Mead-Phoenix Project through a transmission service contract with LADWP. The Authority had outstanding $12,975,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Phoenix Project as of April 1, 2024.

Palo Verde Nuclear Generating Station. The Authority, pursuant to the Arizona Nuclear Power Project Participation Agreement, has a 5.91% ownership interest in Palo Verde Nuclear Generating Station Units 1, 2 and 3 (the "Generating Station"), including certain associated facilities and contractual rights, a 5.44% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard (the "Switchyard") and contractual rights, and a 6.55% share of the rights to use certain portions of Arizona Nuclear Power Project Valley Transmission System. The Generating Station and the Switchyard are collectively referred to herein as "PVNGS."

The Authority has sold the entire capability of the Authority's interest in PVNGS pursuant to power sales contracts with nine California cities and a California irrigation district, each of which is a member of the Authority. The California cities of Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon, as well as LADWP and IID are PVNGS project participants. From and after July 1, 2017, the Authority had no bonds outstanding with respect to PVNGS.

Commercial operation and initial deliveries from PVNGS Units 1, 2 and 3 commenced in 1986 and 1987. In addition to transmission provided by the Mead-Adelanto Project and the Mead-Phoenix Project (described above), transmission is accomplished through agreements with Salt River Project, LADWP and Southern California Edison.

San Juan Unit 3 Project. The San Juan Generating Station ("San Juan") originally consisted of a 4-unit, coal-fired electric generating station located in northwestern New Mexico, approximately 15 miles northwest of the City of Farmington, in San Juan County. The combined net generating capacity of the four units was 1,647 MW, with the net generating capacity of Unit 3 being 497 MW. The four units were put into operation between 1973 and 1982. In 1993, the Authority and five of its members negotiated a purchase agreement with Century Power Corporation, under which the Authority purchased a 41.8% interest in Unit 3 and related common facilities of San Juan, entitling the Authority to approximately 208 MW of power generated by Unit 3. In this regard, the Authority entered into power sales contracts with the California cities of Azusa, Banning, Colton and Glendale, and IID. From and after January 1, 2017, the Authority had no bonds outstanding with respect to San Juan.

As part of the overall settlement of matters regarding emissions at San Juan, Unit 3 permanently ceased operations in December 2017 and effective as of December 31, 2017, the Authority has divested its ownership interest in the San Juan project. However, the Authority retains certain liabilities for a share of the environmental (mine reclamation) and plant decommissioning costs of San Juan, Unit 3.

Magnolia Power Project. The Magnolia Power Project consists of a combined-cycle natural gas-fired electric generating plant with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Power Project is owned by the Authority and was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. The Magnolia Power Project is operated by the California city of Burbank. The Authority has entered into power sales agreements with the California cities of Anaheim, Burbank, Cerritos, Colton, Glendale and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Magnolia Power Project to such participants on a "take-or-pay" basis. The commercial operation date for the Magnolia Power Project was September 22, 2005. The Authority had outstanding $219,005,000 aggregate principal amount of revenue bonds with respect to the Magnolia Power Project as of April 1, 2024 (of which $8,855,000 relates exclusively to the City of Cerritos).

Prepaid Natural Gas Project. The Prepaid Natural Gas Project primarily consists of the acquisition by the Authority of the right to receive an aggregate amount of approximately 135 billion cubic feet of natural gas (which amount has been reduced to approximately 90 billion cubic feet as a result of a restructuring described below) from J. Aron & Company ("J. Aron") pursuant to the terms of five Prepaid Natural Gas Sales Agreements between the Authority and J. Aron, each relating to a separate participant. The gas is delivered by J. Aron to the Authority at designated delivery points on the natural gas pipelines that serve the participants in specified daily quantities each month, over the approximately 30-year term (subsequently amended to a 27-year term due to the restructuring described below) of each of the Prepaid Natural Gas Sales Agreements, in exchange for the lump sum prepayment made to J. Aron by the Authority on the date of issuance of the Authority's Gas Project Revenue Bonds (Project No. 1) in 2007. The Prepaid Natural Gas Project participants are the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between the Authority and J. Aron were restructured to provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreements. As a result of the restructuring, approximately $165,000,000 principal amount of bonds with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured to, among other things, (a) provide additional credit support for payments by three of the project participants by amending and restating the associated receivables purchase agreement and The Goldman Sachs Group, Inc. guaranty, (b) replace AIG-FP Broadgate Limited with Mitsubishi UFJ Securities International plc as the party to the Authority commodity swaps, and (c) create a custodial arrangement with respect to payments owed by J. Aron and guaranteed by The Goldman Sachs Group, Inc. or to J. Aron under corresponding J. Aron commodity swaps in order to mitigate the Authority's credit exposure to Mitsubishi UFJ Securities International plc as the counterparty. The Authority has sold 100% of its interest in the natural gas, on a "take-and-pay" basis, through gas supply agreements with the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. The Authority had outstanding $247,210,000 aggregate principal amount of revenue bonds with respect to the Prepaid Natural Gas Project as of April 1, 2024.

Natural Gas Reserves Project. The Natural Gas Reserves Project includes the Authority's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the "Wyoming Subproject") and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the "Texas Subproject," and collectively with the Wyoming Subproject, the "Natural Gas Reserves Project"). The Authority has sold the entire production capacity of its leasehold interests in the Natural Gas Reserves Project by entering into gas sales agreements with the California cities of Anaheim, Burbank and Colton (collectively, the "Natural Gas Project A Participants") and with the California cities of Glendale and Pasadena on a "take or pay" basis (other than with respect to debt service, which is payable only by the Natural Gas Project A Participants on a several basis). On February 6, 2008, the Authority issued revenue bonds in three simultaneous financings (each for the benefit of a Natural Gas Project A Participant). As of April 1, 2024, the Authority had outstanding $31,190,000 aggregate principal amount of revenue bonds with respect to the Natural Gas Reserves Project, consisting of $17,815,000, $9,660,000 and $3,715,000 aggregate principal amount of the Anaheim series, the Burbank series and the Colton series, respectively.

Canyon Power Project. The Canyon Power Project consists of a simple cycle, natural gas-fired power generating plant, comprised of four General Electric LM 6000PC Sprint combustion turbines with a combined nominally rated net base capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the California city of Anaheim. The Canyon Power Project is owned by the Authority and operated and maintained by Anaheim. The Canyon Power Project was constructed for the primary purpose of providing Anaheim with firm capacity and energy to help it meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The Authority has entered into a power sales agreement with Anaheim pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Canyon Power Project to Anaheim on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $254,540,000 aggregate principal amount of revenue bonds with respect to the Canyon Power Project.

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the "Windy Point Project"). The Windy Point Project is owned and operated by Windy Flats Partners, LLC ("Windy Flats"). Pursuant to a power purchase agreement with Windy Flats, the Authority has agreed to purchase from Windy Flats all energy from the Windy Point Project for an initial delivery term expiring in 2030 (unless earlier terminated). Energy from the Windy Point Project is delivered to the Authority through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. The Authority has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs of energy from the Windy Point Project for the initial delivery term. In March 2023, the original power purchase agreement was amended to extend the delivery term for an additional four (4) years beginning September 10, 2030 through September 9, 2034. In connection with such extension, Windy Flats completed certain equipment replacements and upgrades, which are expected to maintain the project's current capacity factor for the additional four years contemplated by the amendment, plus two more years. The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its output entitlement in the Windy Point Project to such participants on a "take-or-pay" basis. LADWP has purchased Glendale's 7.63% output entitlement share of Windy Point Project's output. As of April 1, 2024, the Authority had outstanding $161,845,000 aggregate principal amount of revenue bonds with respect to the Windy Point Project.

Tieton Hydropower Project. The Tieton Hydropower Project consists of a 13.6 MW nameplate capacity "run of the reservoir" hydroelectric generation facility, comprised of (i) a powerhouse located near Rimrock Lake in Yakima County approximately 40 miles west of the City of Yakima, Washington, and constructed at the base of the Bureau of Reclamation's Tieton Dam on the Tieton River, (ii) a 21-mile 115 kV transmission line from the power plant substation to the point of interconnection with the electrical grid, and (iii) related assets, property and contractual rights, acquired by the Authority in November 2009, pursuant to an Asset Purchase Agreement, dated as of October 19, 2009, by and between the Authority and Tieton Hydropower, L.L.C., a Washington limited liability company. The Authority has entered into power sales and acquisition contracts with the California cities of Burbank and Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Tieton Hydropower Project to such participants on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $30,800,000 principal amount of revenue bonds with respect to the Tieton Hydropower Project.

Linden Wind Energy Project. The Linden Wind Energy Project consists of the acquisition by the Authority of an approximately 50 MW nameplate capacity wind powered electric generating facility comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington, including the structures, facilities, equipment, fixtures, improvements and associated real and personal property and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom. The Linden Wind Energy Project was developed and constructed by Northwest Wind Partners, LLC ("Northwest Wind"), a Delaware limited liability company. Northwest Wind undertook the development, construction, start-up, testing and commissioning of the project, and upon the completion thereof and subject to the terms of the Asset Purchase Agreement, dated as of June 23, 2009, by and between the Authority and Northwest Wind, the Authority acquired the project from Northwest Wind. The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Linden Wind Energy Project to such participants on a "take-or-pay" basis. LADWP has purchased all of Glendale's 10.00% output entitlement share of the Linden Wind Energy Project's output. As of April 1, 2024, the Authority had outstanding $74,765,000 aggregate principal amount of revenue bonds with respect to the Linden Wind Energy Project.

Milford Wind Corridor Phase I Project. *This Project is to be distinguished from the Milford Wind Corridor Phase II Project, which is described below.* The Milford Wind Corridor Phase I Project consists of the purchase by the Authority of all energy generated by a 203.5 MW nameplate capacity wind powered electric generating facility located near Milford, Utah (the "Milford I Facility"), for a term of 20 years (unless earlier terminated), pursuant to a Power Purchase Agreement, dated as of March 16, 2007, as amended, by and between the Authority and Milford Wind Corridor Phase I, LLC, a Delaware limited liability company, as the owner of the Milford I Facility. The generating facility includes 97 wind turbines, consisting of 58 Clipper C99 wind turbine generators, each with a rated capacity of 2.5 MW, and 39 General Electric 1.5 xle wind turbine generators, each with a rated capacity of 1.5 MW. Pursuant to the Power Purchase Agreement, energy from the Milford I Facility is delivered to the Authority over an approximately 88-mile, 345 kV, transmission line extending from the wind generation site to the IPP

Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford I Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On February 9, 2010, the Authority issued $237,235,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford I Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford I Facility (i.e., November 16, 2009). The Authority has entered into power sales agreements with LADWP, and the California cities of Burbank and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase I Project to such participants on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $75,625,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase I Project.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Milford Wind Corridor Phase II Project described below.

Milford Wind Corridor Phase II Project. *This Project is to be distinguished from the Milford Wind Corridor Phase I Project, which is described above.* The Milford Wind Corridor Phase II Project consists of the purchase by the Authority of all energy generated by a 102 MW nameplate capacity, wind powered electric generating facility comprised of 68 wind turbines located near Milford, Utah (the "Milford II Facility"), for a term of 20 years (unless earlier terminated) pursuant to a Power Purchase Agreement, dated as of March 1, 2010, by and between the Authority and Milford Wind Corridor Phase II, LLC, a Delaware limited liability company, as the owner of the Milford II Facility. Pursuant to the Power Purchase Agreement, energy from the Milford II Facility is delivered to the Authority over an approximately 90-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford II Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On August 25, 2011, the Authority issued $157,465,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford II Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford II Facility (i.e., May 2, 2011). The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase II Project to such participants on a "take-or-pay" basis. LADWP has purchased all of Glendale's 4.902% output entitlement share of the Milford II Facility's output. As of April 1, 2024, the Authority had outstanding $66,385,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase II Project.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Milford Wind Corridor Phase I Project described above.

Apex Power Project. The Apex Power Project consists of a natural gas-fired, combined cycle generating facility, nominally rated at 531 MW, located in Clark County, Nevada, generator interconnection facilities, related assets and property, and interconnection and transmission contractual rights. The facility commenced full commercial operation in May 2003. The Apex Power Project was acquired by the Authority in March 2014, pursuant to an Asset Purchase Agreement, dated as of October 17, 2013, by and between the Authority and Las Vegas Power Company, LLC, a Delaware limited liability company, the previous owner of the Apex Power Project. Operation and maintenance of the Apex

Power Project facility is currently provided pursuant to an Operations and Maintenance Agreement with EthosEnergy Power Operations (West), formerly Wood Group Power Operations (West), Inc., and a Long-Term Service Agreement with General Electric International, Inc., each of which was assumed by the Authority in connection with the acquisition of the project. Firm transmission service for the facility output is provided pursuant to a Large Generator Interconnection Agreement with Nevada Power Company and two Service Agreements for Long-Term Firm Point-to-Point Transmission Service with a point of delivery at the Mead 230 kV Substation. The Apex Power Project was acquired by the Authority for the primary purpose of providing LADWP with energy and base-load, combined cycle, gas-fired generating capacity. The Authority has entered into a power sales agreement with LADWP pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Apex Power Project to LADWP on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $230,035,000 aggregate principal amount of revenue bonds with respect to the Apex Power Project.

Other Projects of the Authority Not Financed with Bonds

The following are the projects of the Authority for which no bonds have been issued. The principal of and premium, if any, and interest on the 2024-1 Bonds are secured solely by and payable solely from the Revenues and certain other moneys pledged therefor under the Indenture. None of the costs associated with the projects described below in this subsection is payable from such Revenues and such other moneys pledged to the payment of the 2024-1 Bonds.

Projects Currently Operating

Antelope Big Sky Ranch Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on August 19, 2016. The agreement expires on December 31, 2041.

Antelope DSR I Solar Project. The Authority, on behalf of the California cities of Riverside and Vernon, entered into a power purchase agreement for 50 MW of generating capacity. The commercial operation date for the project was declared on December 20, 2015. The agreement expires on December 19, 2035.

Antelope DSR II Solar Project. The Authority, on behalf of the California city of Azusa, entered into a power purchase agreement for 5 MW of generating capacity. The commercial operation date for the project was declared on December 6, 2016. The agreement expires on December 5, 2036.

Astoria 2 Solar Project. The Authority, on behalf of the California cities of Banning, Colton and Vernon, entered into a power purchase agreement for 35 MW of generating capacity from December 9, 2016 to December 31, 2021 and 45 MW of generating capacity from January 1, 2022 until the expiration of the agreement on December 31, 2036.

Casa Diablo IV Geothermal Project. The Authority, on behalf of the California city of Colton, entered into a power purchase agreement with Ormat for 16 MW of generating capacity. The commercial operation date for the project was declared on July 14, 2022. The agreement expires on July 13, 2047.

Chiquita Canyon Landfill Gas Project. The Authority, on behalf of the California cities of Burbank and Pasadena, entered into a power purchase agreement for 10 MW of generating capacity. The commercial operation date for the project was declared on November 23, 2010. The agreement expires on November 22, 2030.

On February 22, 2024, the Authority received a Notice of Force Majeure from Ameresco Chiquita Energy, LLC ("Ameresco") claiming that they were forced to shut down the facility on January 31, 2024 due to a subsurface chemical reaction in the landfill that has decreased the amount of methane and increased the amount of water vapor in the landfill gas. Additional, Ameresco has claimed that the reported subsurface chemical reaction has introduced dimethyl sulfide ("DMS") into the landfill gas which the facility is not designed to treat or remove. In their notice, Ameresco states that their ability to resume operations depends on the ability of owner of the landfill to restore the landfill gas back to its historic quality and quantity. As of March 26, 2024, no date of return has been provided by Ameresco.

Columbia Two Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 15 MW of generating capacity. The commercial operation date for the project was declared on December 19, 2014. The agreement expires on December 18, 2034.

Copper Mountain Solar 3 Project. The Authority, on behalf of LADWP and the California city of Burbank, entered into a power purchase agreement for 250 MW of generating capacity. The commercial operation date for the project was declared on April 8, 2015. The agreement expires on April 8, 2035.

Coso Geothermal Project. The Authority, on behalf of the California cities of Banning, Pasadena, and Riverside, entered into a power purchase agreement for up to 55 MW of the total 150 MW generating capacity. The delivery commencement date for the project was on January 1, 2022. The agreement expires on December 31, 2041.

Daggett Solar Power 2 Project. The Authority, on behalf of the California cities of Cerritos and Vernon, entered into power purchase agreement for the full output from a facility with a 65 MW solar generating capacity and a 33 MW/132MWh battery energy storage system. The Project achieved its commercial operation date on December 12, 2023. The term of the agreement is 20 years.

Desert Harvest II Solar Project. The Authority, on behalf of the California cities of Anaheim, Burbank, and Vernon, entered into a power purchase agreement for 70 MW of generating capacity. The Project achieved its commercial operation date on December 17, 2020. The term of the agreement is 25 years.

Don A. Campbell I Geothermal Project. The Authority, on behalf of LADWP and the California city of Burbank, entered into a power purchase agreement for approximately 16 MW of net generating capacity. The commercial operation date for the project was declared on January 1, 2014. The agreement expires on January 1, 2034.

Don A. Campbell II Geothermal Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 16 MW of net generating capacity. The commercial operation date for the project was declared on September 17, 2015. The agreement expires on September 17, 2035.

Heber 1 Geothermal Project. The Authority, on behalf of LADWP and IID, entered into a power purchase agreement for 46 MW of generating capacity. The delivery commencement date for the project to the Authority was on February 2, 2016. The agreement expires on February 2, 2026.

Kingbird Solar B Project. The Authority, on behalf of the California cities of Azusa, Colton and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on April 30, 2016. The agreement expires on December 31, 2036, unless a one-time five-year extension is exercised.

ARP-Loyalton Biomass Project. On April 2, 2018, the Authority, on behalf of LADWP, IID and the California cities of Anaheim and Riverside, entered into a power purchase agreement (the "PPA") for approximately 12 MW of generating capacity with ARP-Loyalton Cogen LLC, seller and developer of the existing biomass power generation facility in California. The commercial operation date for the project was declared on April 20, 2018. The agreement expired on April 19, 2023.

In February 2020, the operator of the project, ARP-Loyalton Cogen LLC, and its parent company American Renewable Power LLC, filed petitions for relief under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code"), but both cases have since been converted to Chapter 7 of the Bankruptcy Code, liquidation proceedings. On April 23, 2020, the Chapter 7 trustee entered into an agreement for the sale of the ARP-Loyalton Biomass Project to Sierra Valley Enterprises LLC, a California limited liability company, which sale included substantially all real property and personal property used in the operation of the project. The Bankruptcy Court subsequently approved the sale pursuant to an order entered on May 7, 2020.

Prior to the expiration of the PPA on April 19, 2023, counsel for the Authority worked with counsel for the Chapter 7 trustee to negotiate a mutually agreeable settlement of any claims for damages and reimbursement of the legal costs incurred by the Authority and the other PPA buyers. The parties have now completed their negotiation of the form of a proposed settlement agreement (the "ARP Loyalton Settlement Agreement"). The Authority approved the proposed form of ARP Loyalton Settlement Agreement in January 2024 and recently obtained approvals from all of the other PPA buyers. The parties will now seek approval of the ARP Loyalton Settlement Agreement from the Bankruptcy Court.

Northern Nevada Geothermal Portfolio Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for up to 185 MW of generating capacity. This project is comprised of a portfolio of generating stations to be phased in over time. The first facility began delivering energy to the Authority on December 1, 2017. The last facility of the portfolio reached its delivery commencement date on December 19, 2022. The agreement expires on December 31, 2043.

Ormesa Geothermal Complex Energy Project. The Authority, on behalf of LADWP and IID, entered into a power purchase agreement for 35 MW of net generating capacity. The delivery commencement date for the project to the Authority was on January 1, 2018. The agreement expires on December 31, 2042.

Pebble Springs Wind Power Project. The Authority, on behalf of LADWP and the California cities of Burbank and Glendale, entered into a power purchase agreement for approximately 99 MW of generating capacity. The commercial operation date for the project was declared on January 31, 2009. The agreement expires on January 31, 2027.

Puente Hills Landfill Gas-to-Energy Project. The Authority, on behalf of the California cities of Banning, Colton, Pasadena and Vernon, entered into a power purchase agreement for 46 MW of generating capacity. The delivery commencement date for the project to the Authority was on January 1, 2017. The agreement expires on December 31, 2030.

On March 11, 2024, the Authority received a Notice of Force Majeure from the Los Angeles County Sanitation Districts ("Sanitation Districts") claiming that due to the lower than expected landfill gas production, the Sanitation Districts expect to cease energy sales to the Authority and seek to terminate the power purchase agreement at the end of the day on December 31, 2026.

Red Cloud Wind Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 331 MW of generating capacity. The commercial operation date for the project was declared on December 22, 2021. The term of the agreement is 20 years.

Roseburg Biomass Project. The Authority, on behalf of LADWP, IID and the California city of Anaheim, entered into a purchase agreement for 6.8 MW (out of a total generating capacity of 13.4 MW) pursuant to SB 859. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation and Regulatory Provisions—Biomass Legislation" herein. The delivery commencement date was February 16, 2021. The term of the agreement is five years.

Springbok I Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 105 MW of generating capacity. The commercial operation date for the project was declared on July 11, 2016. The agreement expires on July 10, 2041.

Springbok II Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 155 MW of generating capacity. The commercial operation date for the project was declared on September 6, 2016. The agreement expires on September 5, 2043, unless a one-time three-year extension is exercised.

Springbok III Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 90 MW of generating capacity. The commercial operation date for the project was declared on July 19, 2019. The agreement expires on July 18, 2046, unless a one-time three-year extension is exercised.

Star Peak Geothermal Project. The Authority, on behalf of the California city of Glendale, entered into a power purchase agreement for 12.5 MW of generating capacity. The commercial operation date for the project was declared on September 28, 2022. The agreement expires on December 31, 2045.

Summer Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on July 25, 2016. The agreement expires on December 31, 2041.

Whitegrass Geothermal Project. The Authority, on behalf of the California city of Glendale, entered into a power purchase agreement, for 3.0 MW of generating capacity. The delivery commencement date for the project to the Authority was on April 1, 2020. The agreement expires on December 31, 2045.

Projects Under Development

Bonanza Solar Facility. The Authority, on behalf of the California cities of Azusa and Pasadena, entered into a power purchase agreement for a 125MW portion of the full output from a 300 MW capacity solar facility and a 65MW/260MWh portion of a 195MW/780MWh battery energy storage system. The guaranteed commercial operation date is December 31, 2028. The term of the agreement is 20 years.

Eland Solar & Storage Center, Phases 1 and 2. The Authority, on behalf of LADWP and the California city of Glendale, entered into power purchase agreements for the full output from combined facilities with 400MW solar generating capacity and a 300MW/1,200MWh battery energy storage system. The expected commercial operation date for Phase 1 is September 1, 2024 and the amended expected commercial operation date for Phase 2 is July 31, 2025. The term of the agreements is 25 years.

Geysers Geothermal Project. The Authority, on behalf of the California city of Pasadena, entered into power purchase agreement for a 25 MW portion of the full output from a 725 MW capacity geothermal facility. The guaranteed delivery commencement date is January 1, 2027. The term of the agreement is 15 years.

Sapphire Solar Facility. The Authority, on behalf of the California cities of Anaheim, Pasadena, and Vernon, entered into a power purchase agreement for the full output from a facility with a 117 MW solar generating capacity and a 59MW/236MWh battery energy storage system. The guaranteed commercial operation date is December 31, 2026. The term of the agreement is 20 years.

Further Information

A copy of the Authority's most recent Annual Report may be obtained from the Authority, 1160 Nicole Court, Glendora, California 91740. The Authority and each of the Project Participants maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2024-1 Bonds.

DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS

State Legislation and Regulatory Proceedings

A number of bills affecting the electric utility industry have been introduced or enacted by the California Legislature in recent years. In general, these bills regulate greenhouse gas emissions and provide for greater investment in energy efficiency and environmentally friendly generation and storage alternatives, principally through more stringent renewable resource portfolio standard requirements and more aggressive emissions reduction programs to combat the effects of climate change. More recently, enacted legislation has also focused on addressing issues relating to wildfire risks and occurrences in California, including imposing certain requirements on electric utilities in connection with planning for and mitigating such occurrences and risks. The following is a brief summary of certain of these bills that have been enacted. This discussion does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof.

Greenhouse Gas Emissions – Background; Global Warming Solutions Act. In September 2006, then-Governor Schwarzenegger signed into law Assembly Bill 32, the Global Warming Solutions Act of 2006 (hereinafter, the "GWSA"), which became effective on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of returning to 1990 greenhouse gas emission levels by 2020 as prescribed by Executive Order S-3-05 of the Governor issued on June 1, 2005. In September 2016, then-Governor Brown signed into law Senate Bill 32 ("SB 32"), an amendment to the GWSA. SB 32, which became effective as law on January 1, 2017, codified a new interim statewide greenhouse gas emission reduction target, consistent with Executive Order B-30-15, signed by Governor Brown on April 29, 2015. SB 32 requires the California Air Resources Board ("CARB"), which, pursuant to the GWSA, is the designated state agency charged with monitoring and regulating sources of emissions of greenhouse gases, to ensure that statewide greenhouse gas emissions are reduced to at least 40% below the 1990 level no later than December 31, 2030.

Senate Bill 350 ("SB 350"), signed by then-Governor Brown in October 2015 (and additionally discussed under "*– Renewables Portfolio Standard*" below), requires CARB, in consultation with the California Public Utilities Commission (the "CPUC") and the California Energy Commission, to establish 2030 greenhouse gas emission targets for each electric utility in the State. At present, these targets are non-binding, and primarily intended to help the State measure progress toward the 2030 statewide goal outlined in SB 32. The targets, however, are an input to the integrated resource plans that are required of the State's 16 largest local publicly-owned electric utilities ("POUs"). See "– *Renewables Portfolio Standard*" below.

The GWSA also established an annual mandatory reporting requirement for all investor-owned utilities ("IOUs"), POUs, and other load-serving entities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to CARB, required CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a "cap-and-trade" program) and gave CARB the authority to enforce such regulations beginning in 2012. The Authority and the Project Participants are complying with the applicable reporting requirements under the GWSA.

Assembly Bill 1279 ("AB 1279") established additional greenhouse-gas emission reduction goals. AB 1279 declares the policy of the State both to achieve net-zero greenhouse gas emissions as soon as possible, but no later than 2045, and achieve and maintain net negative greenhouse gas emissions thereafter, and to ensure that by 2045, Statewide anthropogenic greenhouse gas emissions are reduced to at least 85% below the 1990 levels. Under AB 1279, "net zero greenhouse gas emissions" means emissions of greenhouse gases to the atmosphere are balanced by removals of greenhouse gas emissions over a period of time. At present, these targets are non-binding, and primarily intended to help the State progress toward the 2045 Statewide goal outlined in AB 1279.

Greenhouse Gas Emissions – Cap-and-Trade Program. Pursuant to the GWSA, CARB has adopted a series of regulations implementing a cap-and-trade program. The initial cap-and-trade regulation became effective on January 1, 2012. Emission compliance obligations under the regulation began on January 1, 2013. The cap-and-trade program covers sources accounting for 85% of California's greenhouse gas emissions, the largest program of its type in the United States.

The cap-and-trade regulations impose aggregate emissions limitations on the electricity generation industry in California. The cap-and-trade regulations require all regulated entities to obtain and submit to CARB compliance instruments (allowances and/or offsets) with respect to greenhouse gas emissions relating to its State generation activities, as well as for imported electricity from dedicated out-of-state resources. The cap-and-trade program includes the distribution of carbon allowances equal to the annual emissions cap. The Project Participants, like other electric utilities, receive administrative allocations of allowances for some of its expected greenhouse gas emissions. Additional allowances are auctioned quarterly. Entities that emit greenhouse gases at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or on the secondary market from other covered entities with surplus allowances. IOUs are required to auction the allowances they received for free from CARB. This requirement also applies to POUs that sell electricity into the California Independent System Operator Corporation ("ISO") markets, other than sales of electricity from resources funded by municipal tax-exempt debt where the POU makes a matched purchase to serve its traditional retail customers. Utilities required to sell their allowances in the auctions are then required to purchase allowances to meet their compliance obligations, and use any remaining proceeds from the sale of their allocated allowances for the benefit of their ratepayers and to meet the goals of the GWSA. POUs that do not sell into the ISO markets, and those that sell into the ISO markets only electricity from resources funded by municipal tax-exempt debt, have three options (which are not mutually exclusive) once their allocated allowances have been distributed to them. They can (i) place allowances in their compliance accounts to meet compliance obligations, (ii) place allowances in the compliance account of a joint powers agency or public power utility that generates power on their behalf, and/or (iii) auction the allowances and use the proceeds to benefit their ratepayers and meet the goals of the GWSA.

The cap-and-trade program also allows covered entities to use offset credits for compliance (initially not exceeding 8% of a covered entity's compliance obligation through the end of 2020). Offsets can be generated by emission reduction projects in sectors that are not regulated under the cap-and-trade program. CARB has approved the following types of offset projects: urban forest projects, reforestation projects, destruction of ozone-depleting substances, livestock methane management projects, destruction of fugitive coal mine methane and rice cultivation practices. CARB will continue to consider additional and updated offset protocols, including international, sector-based offsets; CARB is also required to reform the offset program pursuant to AB 398 as discussed below.

On July 17, 2017, the California Legislature passed AB 398, extending the cap-and-trade program from 2021 to 2030. AB 398 passed both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, the distribution of free carbon allowances is continued for certain industrial sectors. However, AB 398 imposes stricter limits on the use of offset credits for compliance, with 4% of a covered entity's compliance obligation to be allowed to be satisfied with offsets from 2021 through 2025, and 6% thereafter. In addition, one-half of any such offsets will be required to be in California. Under AB 398, CARB was directed to address the following: establish a price ceiling, offer non-tradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance over-allocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. Under AB 398, CARB was directed to include cost containment provisions to keep allowance prices from rising too high and pushing business expansion outside of the state (referred to as "leakage"). AB 398 was passed in conjunction with AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities. Amendments to the cap-and-trade regulations to reflect the requirements of AB 398 have been adopted by CARB and went into effect on April 1, 2019.

California's cap-and-trade program is linked to the equivalent program in Quebec, Canada. The program may in future years be linked to additional Canadian provincial cap-and-trade programs, and possibly other U.S. state cap-and-trade programs. The Authority and the Project Participants are unable to predict at this time the full impact of the cap-and-trade program over the long-term on the Project Participants' respective electric utilities or on the electric utility industry generally or whether any additional changes to the adopted program will be made.

Since the advent of the cap-and-trade program in 2012, regulations by CARB have provided the electric sector, including the Project Participants, with sufficient allocated greenhouse gas allowances or credits to cover existing operations in meeting retail load obligations. The Project Participants may bank allocated allowances in its compliance account to satisfy a portion of its ongoing compliance obligations. The Project Participants may also buy or sell allowances in the quarterly auctions or on the bi-lateral market to meet its additional compliance obligations. The Project Participants could be adversely affected by future changes in the allowance allocation methodology or by future reductions in the quantity of allowances allocated to it under CARB regulations, if the greenhouse gas emissions of its resource portfolio are in excess of the allowances administratively allocated to it and it is required to purchase compliance instruments on the market to cover its emissions.

Greenhouse Gas Emissions – Emissions Performance Standard. Senate Bill 1368 ("SB 1368") became effective as law on January 1, 2007. SB 1368 provided for an emission performance standard ("EPS"), restricting new investments in baseload fossil fuel electric generating resources that exceed a specified rate of greenhouse gas emissions. SB 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs such as the Project Participants. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide ("CO2") per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

As modified, the EPS regulations require a POU to post a notice of a public meeting at which its governing board will consider any expenditure over $2.5 million to meet environmental regulatory requirements at a non-EPS compliant baseload facility. In addition, each POU is required to file an annual notice identifying all investments over $2.5 million that it anticipates making during the subsequent 12 months on non-EPS compliant baseload facilities to comply with environmental regulatory requirements. This requirement is waived for any POU that has entered into a binding agreement to divest within five years of all baseload facilities exceeding the EPS. CEC staff has confirmed that the $2.5 million threshold applies to an individual investment by each utility, and not the combined investment of all participants in a project.

Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037") was signed by then Governor Schwarzenegger on September 29, 2005. It requires that each POU, including the Project Participants, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost-effective, reliable and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs. The Project Participants are complying with such reporting requirements.

Assembly Bill 2021 ("AB 2021"), signed by then Governor Schwarzenegger on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter for a ten-year horizon. A subsequent amendment, Assembly Bill 2227, extended the time interval for establishing annual targets from every three years to every four years. The Project Participants have complied with this reporting requirement under AB 2021. The information obtained from the POUs from these reporting requirements is utilized by the CEC to present the progress made by the POUs towards the statewide goal to double energy efficiency savings in electricity and natural gas final end uses by 2030, to the extent doing so is cost effective, feasible, and does not adversely impact public health and safety, as prescribed in SB 350. In addition, the CEC can provide recommendations for improvement to assist each POU in achieving cost-effective, reliable, and feasible savings in conjunction with the established targets for reduction. See "*– Renewables Portfolio Standard*" below.

SB 350 further requires the CEC to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The CPUC is required to establish energy efficiency targets for electrical and gas corporations consistent with this goal, and specify programs that may be used to achieve the goal. POUs are required to establish annual targets for energy efficiency savings and demand reduction consistent with the goal and to report those targets to the CEC every four years for the next 10-year period. The bill provides guidance as to what measures qualify and requires an evaluation of feasibility and cost effectiveness in setting annual targets for those savings.

Biomass Legislation. Senate Bill 859 ("SB 859"), signed by then-Governor Brown in September 2016, requires IOUs and POUs that serve more than 100,000 customers to procure, through financial commitments of five years, their proportionate shares (based on the ratio of the utility's peak demand to the total statewide peak demand), of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. Senate Bill 901 ("SB 901"), signed into law in September 2018, requires POUs with certain biomass contracts to seek to extend their term five years past the original expiration date. The Authority has executed power purchase agreements to provide bioenergy to certain members that are subject to the procurement requirements of SB 859 and SB 901 (which includes LADWP but not the other Project Participants). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Projects of the

Authority Not Financed by Bonds – Projects Currently Operating – *ARP-Loyalton Biomass Project*" and " – *Roseburg Biomass Project*." Senate Bill 1109 ("SB 1109") signed into law by Governor Newsom on September 16, 2022 (and effective on January 1, 2023) modifies SB 859's requirement, instead requiring IOUs and POUs that serve more than 100,000 customers to procure, by December 1, 2023, through financial commitments of five to 15 years, their proportionate shares (based on the ratio of the utility's peak demand to the total statewide peak demand), of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. However, such modified requirements under SB 1109 do not apply to a POU if it, either directly or through a joint powers authority, entered into the five-year financial commitments as previously required pursuant to SB 859 and those commitments include (1) a contract with a facility operator that was, on June 1, 2022, in bankruptcy or (2) a contract for a project that does not deliver energy to the POU. The requirements of SB 1109 do not apply to LADWP because LADWP, either directly or through the Authority, entered into the five-year financial commitments as previously required pursuant to SB 859 and the ARP-Loyalton Biomass Project was in bankruptcy on June 1, 2022, and the Roseburg Biomass Project does not deliver energy to LADWP. SB 1109 also modified SB 901's contract extension requirement instead requiring POUs with certain biomass contracts that expire before December 31, 2028, to seek to extend their term five years past the expiration date operative in 2022. These contract extension requirements, similarly, do not apply to LADWP under SB 1109.

Renewables Portfolio Standard. Senate Bill X1-2 ("SBX1-2"), the California Renewable Energy Resources Act, was signed into law by Governor Brown on April 12, 2011. SBX1-2 required each POU to adopt and implement a renewable energy resource procurement plan and established targets for three compliance periods for the procurement of at least the following amounts of electricity products from eligible renewable energy resources, which could include renewable energy certificates ("RECs"), as a proportion of total kilowatt hours sold to the utility's retail end-use customers: (i) over the 2011-2013 compliance period, an average of 20% of retail sales from January 1, 2011 to December 31, 2013, inclusive; (ii) over the 2014-2016 compliance period, a total equal to 20% of 2014 retail sales, 20% of 2015 retail sales, and 25% of 2016 retail sales; and (iii) over the 2017-2020 compliance period, a total equal to 27% of 2017 retail sales, 29% of 2018 retail sales, 31% of 2019 retail sales, and 33% of 2020 retail sales. The governing boards of POUs are responsible for implementing the requirements of SBX1-2, rather than the CPUC, as is the case for the IOUs. In addition, the CEC was given certain enforcement authority for POUs and CARB was given the authority to set penalties. The CEC has developed detailed rules to implement SBX1-2, and has adopted regulations for the enforcement of the RPS program requirements for POUs, which regulations have been subsequently amended from time to time.

SB 350, the Clean Energy and Pollution Reduction Act of 2015, was signed into law by then Governor Brown on October 7, 2015. SB 350, as enacted, establishes an RPS target of 50% by December 31, 2030 for the amount of electricity generated and sold to retail customers from eligible renewable energy resources for retail sellers and POUs, including interim targets of (i) 40% by the end of the 2021-2024 compliance period, (ii) 45% by the end of the 2025-2027 compliance period and (iii) 50% by the end of the 2028-2030 compliance period.

SB 350 requires each retail seller of electricity (including IOUs, most POUs above a certain size threshold, community choice aggregators and energy service providers) to provide a renewable energy procurement plan on an annual basis, and to file an integrated resource plan ("IRP") at least once every five years, commencing no later than January 1, 2019, for CEC review. POUs with an annual electrical demand exceeding 700 gigawatt hours (as determined on a three-year average commencing January 1, 2013) are subject to this requirement, which applies to the State's 16 largest POUs. The governing body of the POU is responsible for adopting the IRP, subject to review by the CEC, which can recommend modifications to correct any shortcomings. This IRP is required to include the affected utility's plans to meet the 2030 interim emissions reductions goal set by CARB. Each of the Project Participants has approved and adopted an integrated resource plan, and the CEC has determined that each of those plans is complete and consistent with the SB 350 requirements.

Senate Bill 100 ("SB 100"), the 100 Percent Clean Energy Act of 2018, was signed into law by then-Governor Brown in September 2018. SB 100 accelerates the State's RPS target as established by SB 350 from 50% by 2030 to 60% by 2030 and sets a goal of 100% "clean energy" by the year 2045. SB 100 requires retail electric sellers and local publicly-owned electric utilities to procure a minimum quantity of electric products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027 and 60% of retail sales by December 31, 2030. SB 100 further establishes a State policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. On the last day of the legislative session, after the passage of SB 100 in both the State Assembly and the State Senate, the bill's author, Senator Kevin de Leon, filed a "Letter to the Journal" clarifying the intent of SB 100, stating that "SB 100 does not seek to require retail sellers of electricity to default on existing contractual obligations to deliver electricity to California customers from existing zero-carbon generating facilities." This clarification allows existing nuclear resources (such as the Palo Verde Nuclear Generating Station) and large hydropower resources (such as Hoover Dam) to help meet the policy standard set forth in SB 100 that eligible renewable and zero-carbon resources supply 100% of retail sales of electricity by December 31, 2045.

In December 2020, the CEC adopted regulations to update the RPS Enforcement Procedures for Publicly Owned Utilities, including to update regulations amended by both SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350, pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of renewables procurement must be for a duration of 10 years or more. The regulations implement the new RPS procurement requirements for the compliance periods between 2021 and 2030, establish soft procurement targets for the intervening years of the compliance periods to demonstrate reasonable progress in meeting the RPS procurement target for the compliance periods, and establish three-year compliance periods beginning after 2030. The regulations also specify standards for 10-year procurement contracts to meet the long-term procurement requirement.

Senate Bill 1020 ("SB 1020"), the Clean Energy, Jobs, and Affordability Act of 2022, signed into law by Governor Newsom on September 16, 2022 (and effective on January 1, 2023), revises SB 100's State policy on eligible renewable energy resources and zero-carbon resources supply. Under the revised State policy, eligible renewable energy resources and zero-carbon resources would supply (i) 90% of all retail sales of electricity to California end-use customers by December 31, 2035, (ii) 95% of all retail sales of electricity to California end-use customers by December 31, 2040, (iii) 100% of all retail sales of electricity to California end-use customers by December 31, 2045, (iv) and 100% of electricity procured to serve all state agencies by December 31, 2035. SB 100 had expressly excluded consideration of the energy, capacity, or any attribute from the Diablo Canyon Unit 1 and Unit 2 nuclear generating facilities in meeting the State's eligible renewable and zero-carbon resources supply policies. SB 1020 eliminates that exclusion.

Legislation Relating to Wildfires; Related Risks. Senate Bill 1028 ("SB 1028") was signed into law by then-Governor Brown in September 2016. SB 1028 requires that each POU and each electric cooperative in the State construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 requires the governing board of each POU to determine, based on historical fire data and local conditions, and in consultation with the fire departments or other entities responsible for the control of wildfires within the geographical area where the utility's overhead electrical lines and equipment are located, whether any portion of that geographical area has a significant risk of wildfire resulting from those electrical lines and equipment, and if so, to present for board approval wildfire mitigation measures the utility intends to undertake to minimize the risk of its overhead electrical lines and equipment causing a catastrophic wildfire.

SB 901, signed into law by then-Governor Brown in September 2018, amends certain provisions of SB 1028 requiring POUs and electric cooperatives to prepare wildfire mitigation measures if the utilities' overhead electrical lines and equipment are located in an area that has a significant risk of wildfire resulting from those electrical lines and equipment. Under SB 901, each POU or electric cooperative was required to prepare a wildfire mitigation plan before January 1, 2020. SB 901 requires the wildfire mitigation plan to be updated annually thereafter. SB 901 requires specified information and elements to be considered as necessary, at minimum, in the wildfire mitigation plan. The POU or electric cooperative is required to present each wildfire mitigation plan in an appropriately noticed public meeting, and to accept comments on its wildfire mitigation plan from the public, other local and state agencies, and interested parties. In addition, SB 901 requires the POU or electric cooperative to contract with a qualified independent evaluator with experience in assessing the safe operation of electrical infrastructure to review and assess the comprehensiveness of its wildfire mitigation plan. The report of the independent evaluator is to be made available to the public and to be presented at a public meeting of the POU's governing board.

Assembly Bill 1054 ("AB 1054") was signed into law by Governor Newsom on July 12, 2019. AB 1054 was enacted as an urgency statute to take effect immediately. AB 1054 establishes a Wildfire Fund of approximately $21 billion to provide liquidity for IOUs to facilitate payment of eligible, uninsured third-party damage claims resulting from future catastrophic wildfires. POUs, including the Project Participants, are not eligible to receive funding from the Wildfire Fund. AB 1054 revises the cost recovery review of wildfire costs and expenses for IOUs before the CPUC, and establishes safety certification protocols that IOUs must meet in order to participate in the Wildfire Fund. AB 1054 provides for a cap on an IOU's obligations to reimburse the Wildfire Fund and a presumption of reasonableness if a utility develops and maintains a valid safety certification. To receive the safety certification from the CPUC, the IOU must develop and implement an approved wildfire mitigation plan, implement the findings of its safety culture assessments, establish a safety committee of its board of directors, establish board level reporting to the CPUC on safety issues, and adopt a compensation structure tied to safety performance, among other requirements. The major IOUs in California are participants in the Wildfire Fund.

AB 1054 expands on the existing requirements established under SB 901 for POUs to develop and implement wildfire mitigation plans. AB 1054 also establishes the California Wildfire Safety Advisory Board (the "Wildfire Advisory Board"), a seven member board appointed by the Governor (five members), the Speaker of the State Assembly (one member) and the State Senate Committee on Rules (one member). The Wildfire Advisory Board advises the Office of Energy Infrastructure Safety on electrical corporations' wildfire mitigation plans, requirements for these plans, and other wildfire safety matters. Additionally, the Wildfire Advisory Board reviews the wildfire mitigation plans submitted by POUs and electrical corporations as discussed in more detail below. The Wildfire Advisory Board also serves as an additional forum for the public to provide input on the important topic of wildfire safety. AB 1054 requires each POU to update its plan annually and to comprehensively revise its plan at least once every three years. Under AB 1054, the Wildfire Advisory Board is required to provide comments and an advisory opinion regarding the content and sufficiency of plans and to make recommendations on how to mitigate wildfire risks. The Project Participants have prepared and submitted wildfire mitigation plans in accordance with the provisions of SB 901 and AB 1054 as required.

A number of significant wildfires have occurred in California every year since 2017. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by the utility's infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County* (2019) 7 Cal.5th 1091, 446 P.3d 304, involving damages related to sewage overflows from a city sewer system, the California Supreme Court held that to succeed on an inverse condemnation claim, a property owner must demonstrate that the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. None of SB 1028, SB 901 or AB 1054 addresses the existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions addresses California's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry, including the Project Participants.

Impact of California Energy Market Developments

The effect of the developments in the California energy markets described above on the Authority and the Project Participants cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors that affect both the supply and demand for and cost of electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet demand at all hours, the availability and cost of renewable energy, the impact of economy-wide greenhouse gas emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impacts of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). See "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY." This price volatility may contribute to greater volatility in the revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect a Project Participant's financial condition. The Project Participants undertake resource planning and risk management activities and manage their respective resource portfolios to mitigate such price volatility and spot market rate exposure.

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 ("EPAct 2005"), FERC was given refund authority over POUs if they sell into short-term markets, like the ISO markets, and sell eight million MWhs or more of electric energy on an annual basis. In addition, FERC was given authority over the behavior of market participants. Under FERC's authority it can impose penalties on any seller for using a manipulative or deceptive device, including market manipulation, in connection with the purchase or sale of energy or of transmission service. The Commodity Futures Trading Commission also has jurisdiction to enforce certain types of market manipulation or deception claims under the Commodity Exchange Act.

EPAct 2005 authorized FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAct 2005 also required the creation of an Electric Reliability Organization ("ERO") to establish and enforce, under FERC supervision, mandatory reliability standards ("Reliability Standards") to increase system reliability and minimize blackouts. Failure to comply with such Reliability Standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards. As described above, EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval. The Reliability Standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each Reliability Standard. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation ("NERC") as the ERO. Many Reliability Standards have since been approved by FERC. Such standards pertain not only to the planning, operations, and maintenance of Bulk-Power System facilities, but also to the cyber and physical security of certain critical facilities.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC ("Regional Entities"), such as the WECC, may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce them. Potential monetary sanctions include fines of up to $1 million per violation per day. FERC Order 693 further provided the ERO and Regional Entities with the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.

Federal Regulation of Transmission Access

EPAct 2005 authorizes FERC to compel "open access" to the transmission systems of certain utilities that are not generally regulated by FERC, including municipal utilities if the utility sells more than four million MWhs of electricity per year. Under open access, a transmission provider must allow all customers to use the system under standardized rates, terms and conditions of service.

FERC Order No. 888 requires the provision of open access transmission services on a nondiscriminatory basis by all "jurisdictional utilities" (which, by definition, does not include municipal entities like the Project Participants) by requiring all such utilities to file Open Access Transmission Tariffs ("OATTs"). Order No. 888 also requires "non-jurisdictional utilities" (which, by definition, does include the Project Participants) that purchase transmission services from a jurisdictional utility under an open access tariff and that own or control transmission facilities to provide open access service to the jurisdictional utility under terms that are comparable to the service that the non-jurisdictional utility provides itself. Section 211A of EPAct 2005 authorizes, but does not require, FERC to order unregulated transmission utilities to provide transmission services. Specifically, FERC may require an unregulated transmitting utility to provide access to their transmission facilities (1) at rates that are comparable to those that the unregulated transmitting utility charges to itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself that are not unduly discriminatory or preferential.

On February 16, 2007, FERC issued Order 890, which concluded that reform of its pro forma OATT was necessary to reduce the potential for undue discrimination and provide clarity in the obligations of transmission providers and customers. Significantly, in Order 890 FERC stated that it will implement its authority under Section 211A with respect to unregulated transmitting utilities on a case-by-case basis and retain the current reciprocity provisions.

On July 21, 2011, FERC issued Order 1000, which among other things requires public utility (jurisdictional) transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and that incorporates a regional and inter-regional cost allocation methodology. Further, FERC states that it has the authority to allocate costs to beneficiaries of transmission services, even in the absence of a contractual relationship between the owner of the transmission facilities and the beneficiary. Under EPAct 2005, FERC may not require municipal utilities to join regional transmission organizations, in which participating utilities allow an independent entity to oversee operation of the utilities' transmission facilities. FERC has stated, however, that FERC expects such utilities to participate in the regional processes for transmission planning and that FERC will pursue associated complaints against such utilities on a case-by-case basis.

At its April 2022 meeting, FERC issued a Notice of Proposed Rulemaking that would, if adopted, result in reforms to the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. The Notice follows input FERC sought from interested parties on a variety of reforms aimed at expanding the nation's transmission grid to accommodate the surge of renewable generation expected in the next two decades to achieve aggressive decarbonization goals of the Biden Administration and many states. The Notice addresses reforms to transmission planning and cost allocation.

Federal Policy on Cybersecurity

On February 13, 2013, then President Obama issued the Executive Order "Improving Critical Infrastructure Security" (the "Infrastructure Security Executive Order"). Among other things, the Infrastructure Security Executive Order called for improved information sharing and processing of security clearances for owners and operators of critical infrastructure. The Infrastructure Security Executive Order further required the Secretary of Commerce to direct the National Institute of Standards and Technology ("NIST") to lead the development of a framework ("Framework") to reduce cyber risks to critical infrastructure. The voluntary Framework will continue to be updated and improved as industry provides feedback on implementation.

The Cybersecurity Information Sharing Act of 2015 was signed into law on December 18, 2015 as part of the year-end Omnibus Appropriations Act. It creates an industry-supported, voluntary cybersecurity information sharing program that encourages both public and private sector entities to share cyber-related threat information. The Authority supported passage of the bill.

In September 2018, then President Trump signed the "National Cyber Strategy," which sought to update the nation's cybersecurity strategy for the first time in 15 years – and identified "energy and power" as one of the seven key areas for protection. FERC has also sought to expand reporting rules for incidents involving attempts to compromise operation of the electric grid and address supply chain cybersecurity risks.

In March of 2023, the Biden administration adopted the 2023 National Cybersecurity Strategy. The 2023 National Cybersecurity Strategy replaces but continues momentum on many of the priorities of the 2018 National Cyber Strategy. The 2023 National Cybersecurity Strategy seeks to build and enhance collaboration around five pillars: (1) Defend Critical Infrastructure; (2) Disrupt and Dismantle Threat Actors; (3) Shape Market Forces to Drive Security and Resilience; (4) Invest in a Resilient Future; and (5) Forge International Partnerships to Pursue Shared Goals.

Environmental Issues

General. Electric utilities are subject to continuing environmental regulation. Federal, State and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any facilities or projects of the Authority or the Project Participants will remain subject to the laws and regulations currently in effect, will always be in compliance with future laws and regulations or will always be able to obtain all required operating permits. In addition, the election of new administrations, including the President of the United States, could impact substantially the current environmental standards and regulations and other matters described herein. For example, President Biden issued an executive order requiring agencies to consider suspending, revising or rescinding multiple environmental standards and regulations imposed during the prior administration. An inability to comply with environmental standards could result in, for example, additional capital expenditures, reduced operating levels or the shutdown of individual units not in compliance. In addition, increased environmental laws and regulations may create certain barriers to new facility development, may require modification of existing facilities and may result in additional costs for affected resources.

Greenhouse Gas Regulations Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates greenhouse gas emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, greenhouse gases are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies ("BACT") to control emissions at a facility. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. Greenhouse gases from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

In May 2023, the EPA proposed new regulations under the Clean Air Act that would establish greenhouse gas emission limits, based on pollution control technology or lower-carbon fuels, for new gas plants, existing gas plants, and existing coal plants, as specified. The proposed rule is not yet final.

Air Quality – National Ambient Air Quality Standards. The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards ("NAAQS") for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the applicable standard and become an "attainment area." The EPA periodically reviews the NAAQS for various air pollutants and has in recent years increased, or proposed to increase, the stringency of the NAAQS for certain air pollutants. These developments may result in stringent permitting processes for new sources of emissions and additional state restrictions on existing sources of emissions, such as power plants.

In addition, the U.S. Supreme Court found in its review of *EPA v. EME Homer City Generation*, LP that the EPA has authority to impose a Cross-State Air Pollution Rule (the "Transport Rule") which curbs air pollution emitted in upwind states to facilitate downwind attainment of three NAAQS. On November 26, 2014, the EPA proposed to strengthen the stringency of the NAAQS for ozone by lowering the existing ozone standard of 75 parts per billion ("ppb") to between 65 and 70 ppb, although the EPA also sought public comment on a standard as low as 60 ppb. On October 1, 2015, the EPA issued its final rule, lowering the ozone standard to 70 ppb. Legal challenges to the final rule were filed by a number of states and industry groups. On March 12, 2018, a federal district judge in Northern California ordered the EPA to complete the strengthened 2015 ozone standard designations later in 2018. The EPA noticed a final rule on December 6, 2018 implementing ozone NAAQS for non-attainment areas and addressing state implementation plan requirements. That rule became effective on February 4, 2019.

On July 15, 2020, the EPA announced a proposed decision to retain the existing 70 ppb ozone standard. The decision was finalized on December 7, 2020. In August 2023, the EPA announced a new review of the ozone NAAQS to support consideration of new information and advice.

On June 10, 2021, the EPA announced that it will reconsider the previous administration's decision to retain the particulate matter NAAQS, which were last strengthened in 2012. The EPA stated that it is reconsidering the previous administration's December 2020 decision to retain existing standards because available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the Clean Air Act. While some particulate matter is emitted directly from sources such as construction sites, unpaved roads, fields, smokestacks or fires, most particles form in the atmosphere as a result of complex reactions of chemicals such as sulfur dioxide and nitrogen oxides, which are pollutants emitted from power plants and other sources. On January 6, 2023, the EPA proposed regulations imposing tighter limits on particulate matter emissions. The proposed rule is not yet final.

Mercury and Air Toxics Standards. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants, including mercury. On February 16, 2012, the EPA finalized a rule, the Mercury and Air Toxics Standards ("MATS"), establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards, or "NSPS") and 112 (toxics program) of the Clean Air Act. The rule was subsequently amended in 2013 and 2014. Under section 111 of the Clean Air Act, the MATS rule revised the standards that new and modified facilities, including coal- and oil-fired power plants, must meet for particulate matter, sulfur dioxide, and nitrogen oxide. Under section 112, the MATS rule set new toxics standards limiting emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid, from existing and new power plants larger than 25 MW that burn coal or oil. Power plants would have up to four years to meet these standards. While many plants already meet some or all of these revised standards, some plants would be required to install new equipment to meet the standards. The rule has minimal impact to the Authority and the Project Participants. IPP, which has coal-fired power plants, did not have to install control technology, and the EPA has deemed the IPP units as low-emitting units. IPP is subject to periodic testing, work practice standards and recordkeeping requirements as a result of the rule. On July 17, 2020, the EPA finalized revisions to the electronic reporting requirements for MATS that revised and streamlined the reporting requirements and provided enhanced access to MATS data, without imposing new monitoring requirements. In April 2023, the EPA published a proposed rule that would modify regulation of coal- and oil-fired power plants, including further restricting their emissions and changing emissions monitoring requirements. The proposed rule is not yet final.

Effluent Limitations Guidelines and Standards. On June 7, 2013, the EPA proposed to set technology-based effluent limitations guidelines and standards for metals and other pollutants in wastewater discharged from steam electric power plants. The proposal would cover wastewater associated with several types of equipment and processes, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control and gasification of fuels. The EPA considered best management practices for surface impoundments containing coal combustion residuals. The EPA proposed four preferred alternatives for regulating wastewater discharges. The stringency of controls, types of waste streams covered, and the costs varied among the four alternatives. On September 30, 2015, the EPA announced its final Steam Electric Effluent Limitation Guidelines to update the federal limits on toxic metals in discharge wastewater. On June 6, 2017, the Trump Administration announced that it was postponing certain compliance dates in the effluent limitation guidelines and standards for the new, more stringent steam electric point source category under the Clean Water Act until the EPA completes reconsideration of the 2015 rule. On May 2, 2018, the EPA noticed the Final 2016 Effluent Guidelines Program Plan, which identified one new rulemaking (and the associated schedule) for the steam electric power generating point source category. The proposed rule was published in November 2019, a public hearing on the proposed rule was held on December 19, 2019, and the final rule for steam electric power generation point source was published on August 31, 2020. On August 3, 2021, the EPA announced a planned-rulemaking to strengthen certain discharge limits in the steam electric power generating category. The EPA published a proposed rule in March 2023. The rule was finalized in May 2023.

Changing Laws and Requirements Generally

Congress has considered and is considering numerous bills addressing domestic energy policies and various environmental matters, including bills relating to energy supplies and financial incentives for development, climate change and reduction or elimination of net carbon dioxide emission attributable to the electricity grid and the economy more generally. Many of these bills, if enacted into law, could have a material impact on the Authority, the Project Participants and the electric utility industry generally. In light of the variety of issues affecting the utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements, and cybersecurity is also possible. However, the Authority and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation on the Project Participants' respective electric utilities at this time.

Other Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors discussed above, such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements other than those described above (including those affecting nuclear power plants or potential new energy storage requirements), (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) effects on the integration and reliability of power supply from the increased usage of renewables, (d) changes resulting from a national energy policy, (e) effects of competition from other electric utilities (including increased competition resulting from a movement to allow direct access or expanded community choice aggregation or from mergers, acquisitions, and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity, (f) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many IOUs, (g) increased competition from independent power producers and marketers, brokers and federal power marketing agencies, (h) "self-generation" or "distributed generation" (such as microturbines, fuel cells and solar installations) by industrial and commercial customers and others, (i) issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission service from transmission line projects financed with outstanding tax-exempt obligations and, as of January 1, 2018, the loss of the ability to undertake tax-exempt advance refundings, (j) effects of inflation on the operating and maintenance costs of an electric utility and its facilities, (k) changes from projected future load requirements, (l) increases in costs and uncertain availability of capital, (m) shifts in the availability and relative costs of different fuels (including the cost of natural gas and nuclear fuel), (n) changes in the electric market structure for neighboring electric grids, such as the energy imbalance market operated by the ISO, (o) sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the past in California, (p) issues relating to risk management procedures and practices with respect to, among other things, the purchase and sale of natural gas, energy and transmission capacity, (q) other legislative changes, voter initiatives, referenda and statewide propositions, (r) effects of the changes in the economy, population and demand of customers within a utility's service area, (s) effects of possible manipulation of the electric markets, (t) acts of terrorism or cyber-terrorism impacting a utility and/or significant load customers, (u) changes to the climate; (v) natural disasters or other physical calamities, including, but not limited to, earthquakes, droughts, severe weather, floods and wildfires, and potential liabilities of electric utilities in connection therewith, and (w) adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk. Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

The Authority is unable to predict what impacts such factors will have on the business operations and financial condition of the Project Participants' respective electric systems, but the impacts could be significant. Although this Official Statement includes a brief discussion of certain of these factors, this discussion does not purport to be comprehensive or definitive; and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain, and potential purchasers of the 2024-1 Bonds should obtain and review such information.

CONSTITUTIONAL LIMITATIONS IN CALIFORNIA AFFECTING FEES AND CHARGES IMPOSED BY THE PROJECT PARTICIPANTS

The following is a discussion of certain limitations under provisions of the California Constitution that may affect the rates, fees and charges imposed by the Project Participants for the electric services they provide.

Proposition 218 and Proposition 26

Proposition 218, a State ballot initiative known as the "Right to Vote on Taxes Act," was approved by the voters of the State of California on November 5, 1996. Proposition 218 added Articles XIIIC and XIIID to the State Constitution. Article XIIIC imposes a majority voter approval requirement on local governments (including the Project Participants) with respect to taxes for general purposes, and a two-thirds voter approval requirement with respect to taxes for special purposes. Article XIIID creates additional requirements for the imposition by most local governments of general taxes, special taxes, assessments and "property-related" fees and charges. Article XIIID explicitly exempts fees for the provision of electric service from the provisions of such article.

Article XIIIC expressly extends the people's initiative power to the reduction or repeal of local taxes, assessments, and fees and charges imposed prior to its effective date (November 1996). The California Supreme Court held in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal.4th 205 (2006) that, under Article XIIIC, local voters by initiative may reduce a public agency's water rates and delivery charges, as those are property-related fees or charges within the meaning of Article XIIID, and noted that the initiative power described in Article XIIIC may extend to a broader category of fees and charges than the property-related fees and charges governed by Article XIIID. Moreover, in the case of *Bock v. City Council of Lompoc*, 109 Cal.App.3d 52 (1980), the Court of Appeal determined that an electric rate ordinance was not subject to the same constitutional restrictions that are applied to the use of the initiative process for tax measures so as to render it an improper subject of the initiative process. Thus, electric service charges (which are expressly exempted from the provisions of Article XIIID) may be subject to the initiative provisions of Article XIIIC, thereby subjecting such fees and charges to reduction by the electorate. The Authority believes that even if the electric rates of the Project Participants are subject to the initiative power, under Article XIIIC or otherwise, the electorate of the Project Participants would be precluded from reducing electric rates and charges in a manner materially and adversely affecting the payment of the 2024-1 Bonds by virtue of the "impairment of contracts clause" of the United States Constitution.

The California electorate approved Proposition 26 at the November 2, 2010 election, amending Article XIIIC of the California Constitution. Proposition 26 was designed to supplement tax limitations California voters adopted when they approved Proposition 13 in 1978, and Proposition 218 in 1996. Proposition 26 applies by its terms to any levy, charge or exaction imposed, increased or extended by a local government on or after November 3, 2010. Proposition 26 deems any such levy, charge or fee to be a "tax", requiring voter approval under Article XIIIC unless it comes within one of the listed exceptions. Proposition 26 expressly excludes from its definition of a "tax," among other things, a "charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product." Proposition 26 is applicable to the electric rates of governmental entities such as the Project Participants; therefore, newly adopted rates must conform to its requirements.

Proposition 26 is subject to interpretation by California courts, including the extent to which it is applicable to pre-existing electric rates and general fund transfers. A number of lawsuits have been filed against public agencies in California relating to electric utility fund transfers. In *Citizens for Fair REU Rates v. City of Redding* (filed on January 20, 2015 and modified on February 19, 2015), for example, the California Court of Appeal considered a ratepayer challenge to a "payment in lieu of taxes" (or "PILOT") required by the City of Redding to be made by its electric utility as an annual budgetary transfer amount without voter approval. The city's PILOT was designed to compensate the general fund for the costs of services that other city departments provide to the electric utility. The amount of the PILOT was equivalent to the ad valorem taxes the electric utility would have had to pay if the electric utility were privately owned. The suits alleged that the PILOT was passed through to the city's electric utility customers as part of the rates and charges for electric service in excess of the reasonable costs to the city of providing electric service. The Court of Appeal determined that Proposition 26 has no retroactive effect as to local taxes that existed prior to November 3, 2010, but found that since the PILOT was subject to the City Council's recurring discretion, the PILOT did not escape the purview of Proposition 26. The Court of Appeal concluded that the PILOT constituted a "tax" under Proposition 26 for which the city must secure voter approval unless the city proved that the amount collected was necessary to cover the reasonable costs to the city of providing electric service. On April 29, 2015, the California Supreme Court granted review of the decision of the Court of Appeal. The California Supreme Court rendered its decision on August 27, 2018, reversing the judgment of the Court of Appeal. The California Supreme Court determined that the budgetary transfer from the City of Redding electric utility to the city's general fund, calculated by using the PILOT, itself is not the type of exaction that is subject to Article XIIIC of the California Constitution. The court reasoned that it is only the City of Redding electric utility rate, not the PILOT, that is imposed on customers for electric service. The California Supreme Court concluded that because the total retail rate revenue of the electric utility was insufficient to cover the electric utility's uncontested operating expenses (other than the PILOT) in the years at issue, the challenged rate did not exceed the reasonable costs of providing electric service, and therefore did not constitute a tax.

The Authority and the Project Participants are unable to predict at this time how Propositions 218 and 26 will ultimately be interpreted by the courts in the context of the Project Participants' respective electric system rates or what the ultimate impact of Propositions 218 or 26 will be.

Other Initiatives

Articles XIIIC and XIIID and the amendments effected thereto by Proposition 26 were adopted as measures that qualified for the ballot pursuant to California's initiative process. From time to time, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be adopted affecting the Authority's and/or the Project Participants' revenues or operations. Neither the nature and impact of these measures nor the likelihood of qualification for ballot or passage can be predicted by the Authority or the Project Participants.

A voter initiative entitled "The Taxpayer Protection and Government Accountability Act" ("Initiative 1935") was recently determined to be eligible for the November 2024 Statewide general election and will be certified as qualified for the ballot in such election, unless withdrawn by its proponent prior to June 27, 2024 or a pending court challenge is successful in preventing Initiative 1935 from appearing on the ballot. Were it to be adopted by the voters in the Statewide general election, Initiative 1935 would amend the California Constitution to provide, among other things, that charges for services or product provided directly to the payor (such as charges for electricity) are "taxes" subject to voter approval unless the local government can prove by clear and convincing evidence that the charge is reasonable and does not exceed the "actual cost" of providing the service or product, defined as "(i) the minimum amount necessary to reimburse the government for the cost of providing the service or the product to the payor, and (ii) where the amount charged is not used by the government for any purpose other than reimbursing that cost." If adopted, Initiative 1935 would be subject to judicial interpretation. Neither the Authority nor the Project Participants are able to predict whether and how Initiative 1935, if adopted, would be interpreted by the courts, and there can be no assurance that any such interpretation or application would not have an adverse impact on the Project Participants, their respective electric utilities or the revenues of their respective electric utilities.

LITIGATION

At the time of delivery of the 2024-1 Bonds, an authorized officer of the Authority will certify that, to the knowledge of such officer, there is no litigation or other proceeding pending or threatened in any court, agency or other administrative body (either State of California or federal) restraining or enjoining the issuance, sale or delivery of the 2024-1 Bonds or the collection of Revenues, or in any way questioning or affecting (i) the Authority's power, or any authority, for the issuance of the 2024-1 Bonds, (ii) the validity of any provision of the 2024-1 Bonds or the Indenture, (iii) the pledge by the Authority under the Indenture, (iv) the validity or enforceability of the Renewal Transmission Service Contracts, (v) the legal existence of the Authority or the title to office of the present officials of the Authority or (vi) the authority of the Authority to undertake the Southern Transmission System Renewal Project.

TAX MATTERS

Federal Income Taxes

The Internal Revenue Code of 1986, as amended (the "Code"), imposes certain requirements that must be met subsequent to the issuance and delivery of the 2024-1 Bonds for interest thereon to be and remain excluded from gross income for federal income tax purposes. Noncompliance with such requirements could cause the interest on the Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the 2024-1 Bonds. Pursuant to the Indenture and the Tax and Nonarbitrage Certificate (the "Tax Certificate"), the Authority has covenanted to comply with the applicable requirements of the Code in order to maintain the exclusion of the interest on the 2024-1 Bonds from gross income for federal income tax purposes pursuant to Section 103 of the Code. In addition, the Authority has made certain representations and certifications in the Indenture and the Tax Certificate. Special Tax Counsel will not independently verify the accuracy of those representations and certifications.

In the opinion of Nixon Peabody LLP, Special Tax Counsel, under existing law and assuming compliance with the aforementioned covenant, and the accuracy of certain representations and certifications made by the Authority described above, interest on the 2024-1 Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Code. Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code. Interest on the 2024-1 Bonds will be taken into account in computing the alternative minimum tax imposed on certain corporations under the Code to the extent that such interest is included in the "adjusted financial statement income" of such corporations.

State Taxes

Special Tax Counsel is also of the opinion that interest on the 2024-1 Bonds is exempt from personal income taxes of the State of California (the "State") under present State law. Special Tax Counsel expresses no opinion as to other State or local tax consequences arising with respect to the 2024-1 Bonds nor as to the taxability of the 2024-1 Bonds or the income therefrom under the laws of any state other than the State of California.

Original Issue Discount

Special Tax Counsel is further of the opinion that the excess of the principal amount of a maturity of the 2024-1 Bonds over its issue price (i.e., the first price at which price a substantial amount of such maturity of the 2024-1 Bonds was sold to the public, excluding bond houses, brokers or similar persons or organizations acting in the capacity of underwriters or wholesalers) (each, a "Discount Bond" and collectively the "Discount Bonds") constitutes original issue discount which is excluded from gross income for federal income tax purposes to the same extent as interest on the 2024-1 Bonds. Further, such original issue discount accrues actuarially on a constant interest rate basis over the term of each Discount Bond and the basis of each Discount Bond acquired at such issue price by an initial purchaser thereof will be increased by the amount of such accrued original issue discount. The accrual of original issue discount may be taken into account as an increase in the amount of tax-exempt income for purposes of determining various other tax consequences of owning the Discount Bonds, even though there will not be a corresponding cash payment. Owners of the Discount Bonds are advised that they should consult with their own advisors with respect to the state and local tax consequences of owning such Discount Bonds.

Original Issue Premium

2024-1 Bonds sold at prices in excess of their principal amounts are "Premium Bonds". An initial purchaser with an initial adjusted basis in a Premium Bond in excess of its principal amount will have amortizable bond premium which offsets the amount of tax-exempt interest and is not deductible from gross income for federal income tax purposes. The amount of amortizable bond premium for a taxable year is determined actuarially on a constant interest rate basis over the term of each Premium Bond based on the purchaser's yield to maturity (or, in the case of Premium Bonds callable prior to their maturity, over the period to the call date, based on the purchaser's yield to the call date and giving effect to any call premium). For purposes of determining gain or loss on the sale or other disposition of a Premium Bond, an initial purchaser who acquires such obligation with an amortizable bond premium is required to decrease such purchaser's adjusted basis in such Premium Bond annually by the amount of amortizable bond premium for the taxable year. The amortization of bond premium may be taken into account as a reduction in the amount of tax-exempt income for purposes of determining various other tax consequences of owning such 2024-1 Bonds. Owners of the Premium Bonds are advised that they should consult with their own advisors with respect to the state and local tax consequences of owning such Premium Bonds.

Ancillary Tax Matters

Ownership of the 2024-1 Bonds may result in other federal tax consequences to certain taxpayers, including, without limitation, certain S corporations, foreign corporations with branches in the United States, property and casualty insurance companies, individuals receiving Social Security or Railroad Retirement benefits, individuals seeking to claim the earned income credit, and taxpayers (including banks, thrift institutions and other financial institutions) who may be deemed to have incurred or continued indebtedness to purchase or to carry the 2024-1 Bonds. Prospective investors are advised to consult their own tax advisors regarding these rules.

Interest paid on tax-exempt obligations such as the 2024-1 Bonds is subject to information reporting to the Internal Revenue Service (the "IRS") in a manner similar to interest paid on taxable obligations. In addition, interest on the Bonds may be subject to backup withholding if such interest is paid to a registered owner that (a) fails to provide certain identifying information (such as the registered owner's taxpayer identification number) in the manner required by the IRS, or (b) has been identified by the IRS as being subject to backup withholding.

Special Tax Counsel is not rendering any opinion as to any federal tax matters other than those described in the opinions attached as Appendix F. Prospective investors, particularly those who may be subject to special rules described above, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the 2024-1 Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

Changes in Law and Post Issuance Events

Legislative or administrative actions and court decisions, at either the federal or state level, could have an adverse impact on the potential benefits of the exclusion from gross income of the interest on the 2024-1 Bonds for federal or state income tax purposes, and thus on the value or marketability of the 2024-1 Bonds. This could result from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), repeal of the exclusion of the interest on the 2024-1 Bonds from gross income for federal or state income tax purposes, or otherwise. It is not possible to predict whether any legislative or administrative actions or court decisions having an adverse impact on the federal or state income tax treatment of holders of the 2024-1 Bonds may occur. Prospective purchasers of the 2024-1 Bonds should consult their own tax advisors regarding the impact of any change in law on the 2024-1 Bonds.

Special Tax Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the 2024-1 Bonds may affect the tax status of interest on the 2024-1 Bonds. Special Tax Counsel expresses no opinion as to any federal, state or local tax law consequences with respect to the 2024-1 Bonds, or the interest thereon, if any action is taken with respect to the 2024-1 Bonds or the proceeds thereof upon the advice or approval of other counsel.

RATINGS

Moody's Investors Service, Inc. and Fitch Ratings, Inc. have assigned the 2024-1 Bonds the credit ratings of "[__]" and "[__]," respectively. No application has been made to any other rating agency in order to obtain additional ratings on the 2024-1 Bonds. Each credit rating should be evaluated independently of any other rating. Generally, a rating agency bases its rating on the information and materials furnished to it and on investigations, studies and assumptions of its own. A credit rating reflects only the view of the organization furnishing the same and any desired explanation of the significance of such rating should be obtained from the rating agency furnishing the same.

The above described ratings are not a recommendation to buy, sell or hold the 2024-1 Bonds. There is no assurance that any such rating will continue for any given period or that it will not be revised downward or withdrawn entirely by the rating agency furnishing such rating, if in the judgment of such rating agency, circumstances so warrant. The Authority undertakes no responsibility to oppose any such revision or withdrawal. Any downward revision or withdrawal of a credit rating may have an adverse effect on the market price of the 2024-1 Bonds.

UNDERWRITING

The 2024-1 Bonds will be purchased for reoffering by Barclays Capital Inc., RBC Capital Markets, BofA Securities, Inc., Loop Capital Markets LLC, Samuel A. Ramirez & Co., Inc., Siebert Williams Shank & Co., LLC and TD Securities (USA) LLC (the "Underwriters"), at a purchase price of $___________, representing the par amount of the 2024-1 Bonds of $___________, plus [net] original issue premium of $___________, and less an Underwriters' discount of $___________. The Underwriters will be obligated to purchase all of the 2024-1 Bonds if any of the 2024-1 Bonds are purchased.

The Underwriters may offer and sell the 2024-1 Bonds to certain dealers (including dealers depositing 2024-1 Bonds into investment trusts) and others at prices lower than the respective public offering prices stated or derived from information stated on the inside cover page hereof. The initial public offering prices may be changed from time to time by the Underwriters.

[Underwriter disclosures]

CERTAIN RELATIONSHIPS

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Under certain circumstances, the Underwriters and their respective affiliates may have certain creditor and/or other rights against the Authority and the Project Participants in connection with such activities. The Underwriters and their respective affiliates have, from time to time, performed and may in the future perform, various investment banking services for the Authority, for which they received or will receive customary fees and expenses.

In the course of their various business activities, the Underwriters and their respective affiliates, may purchase, sell or hold a broad array of investments and actively traded securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of the Authority (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with the Authority.

The Underwriters and their respective affiliates may also communicate independent investment recommendations, market advice or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

MUNICIPAL ADVISOR

The Authority has retained PFM Financial Advisors LLC, Los Angeles, California, as Municipal Advisor (the "Municipal Advisor") in connection with the issuance of the 2024-1 Bonds. The Municipal Advisor has not undertaken to make an independent verification or to assume responsibility for the accuracy, completeness, or fairness of the information contained in this Official Statement. The Municipal Advisor is an independent financial advisory firm and is not engaged in the business of underwriting, trading or distributing municipal securities or other public securities. The payment of the fees of the Municipal Advisor is contingent upon the issuance and delivery of the 2024-1 Bonds.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 2024-1 Bonds are subject to the approval of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel. The form of opinion that Bond Counsel proposes to render with respect to the 2024-1 Bonds is attached as Appendix E hereto. Certain other legal matters with respect to the Authority will be passed upon by its General Counsel, Christine Godinez, Esq., and by Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel. The form of opinion that Special Tax Counsel proposes to render with respect to the 2024-1 Bonds is attached as Appendix F hereto. Bond Counsel will not address any of the tax aspects of the 2024-1 Bonds. Certain legal matters will be passed upon for the Underwriters by their counsel, Hawkins Delafield & Wood LLP, Sacramento, California. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2024-1 Bonds.

CONTINUING DISCLOSURE UNDERTAKING FOR THE 2024-1 BONDS

Pursuant to the Continuing Disclosure Resolution of the Authority's Board of Directors, the Authority has agreed for the benefit of the registered owners and the "Beneficial Owners" of the 2024-1 Bonds to provide certain financial information and operating data relating to the Authority and LADWP by not later than six months after the end of each of the Authority's fiscal years (presently, by each December 31) commencing with fiscal year 2023-24 (the "Annual Report"), and to provide notices of the occurrence of certain specified events with respect to the 2024-1 Bonds. The Annual Report will be filed by or on behalf of the Authority with the Municipal Securities Rulemaking Board ("MSRB") through the MSRB's Electronic Municipal Market Access ("EMMA") system. The notices of such events will also be filed by or on behalf of the Authority with the MSRB through the EMMA system. The specific nature of the information to be contained in the Annual Report and the notices of events is set forth in the form of the Continuing Disclosure Resolution which is included in its entirety in Appendix D hereto. The Authority's continuing disclosure undertaking has been made in order to assist the Underwriters in complying with SEC Rule 15c2-12.

The Authority is in compliance in all material respects with its continuing disclosure undertakings for the last five years. During the last five years, the Authority has filed annual reports for between 13 and 16 different projects for which it has issued revenue bonds. In the last five years, although the Authority generally has routinely filed notices of known instances of rating changes in connection with its revenue bonds, two rating changes in each of 2022 and 2023 were inadvertently not updated. Filings have been posted with EMMA to update the ratings. Lastly, for the fiscal year 2019-20 annual report relating to the Authority's Magnolia Power Project A, Refunding Revenue Bonds, 2020-1 and 2020-3, the audited financial statements of the Anaheim Public Utilities Department were timely filed but inadvertently were not linked to all relevant CUSIP numbers. The Authority has since caused such information to be linked to all relevant CUSIP numbers. The Authority believes it has established processes to ensure it will continue to comply in all material respects with its continuing disclosure undertakings in the future.

AVAILABLE INFORMATION

Copies of the Authority's most recent audited financial statements and Annual Report, and copies of the forms of the Renewal Transmission Service Contracts, the Renewal Capacity Acquisition Agreements, the Original Southern Transmission System Agreement, the Renewal Southern Transmission System Agreement, Original Power Sales Contracts, the Renewal Power Sales Contracts, the Renewal Agency Agreement and the Indenture are available from the Authority, 1160 Nicole Court, Glendora, California 91740.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By ____
Interim Executive Director

APPENDIX A

THE PROJECT PARTICIPANT WITH THE LARGEST RENEWAL TRANSMISSION SERVICE SHARE

THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

The following information concerning The Department of Water and Power of the City of Los Angeles (in this section, the "Department") and such Department's Power System, has been prepared by the Department for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Department or the Power System. A copy of the most recent audited financial statements of the Power System (the "Department's Power System Financial Statements") may be obtained from Peter Huynh, Assistant Chief Financial Officer and Treasurer of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012, and is also available on the Electronic Municipal Market Access ("EMMA") website of the Municipal Securities Rulemaking Board ("MSRB"), currently located at http://emma.msrb.org. The Department's Power System Financial Statements are incorporated herein by this reference. However, other information presented on such website or referenced therein other than the Department's Power System Financial Statements is not part of this Official Statement and is not by reference to such website incorporated herein.

GENERAL

The Department is the largest municipal utility in the United States and is a proprietary department of the City of Los Angeles (the "City"). Control of Power System assets and funds is vested with the Board of Water and Power Commissioners of the City of Los Angeles (the "Board"), whose actions are subject to review by the City Council of the City (the "City Council"). The Department is responsible for providing the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City. The City encompasses approximately 473 square miles and is populated by approximately 3.8 million residents.

Department operations began in the early years of the twentieth century. The first Board of Power Commissioners was established in 1902. Nine years later, the responsibilities for the provision of electricity and water within the City were given to the Los Angeles Department of Public Service (the "Department of Public Service"). The Department of Public Service was superseded in 1925 with passage of the 1925 Charter and the creation of the Department. The Department now operates under the Charter adopted in 2000. The operations and finances of the Water System are separate from those of the Power System.

A copy of the most recent official statement or offering memorandum prepared by the Department for the issuance of securities for its Power System may be obtained from Peter Huynh, Assistant Chief Financial Officer and Treasurer of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012, or is available from the MSRB through its EMMA system.

Charter Provisions

Pursuant to the Charter, the Board is the governing body of the Department and the General Manager of the Department (the "General Manager") administers the affairs of the Department.

The Charter provides that all revenue from every source collected by the Department in connection with its possession, management and control of the Power System is to be deposited in the Power Revenue Fund. The Charter further provides that the Board controls the money in the Power Revenue Fund and makes provision for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund. The procedure relating to the authorization of the issuance of bonds is governed by Section 609 of the Charter.

Section 245 of the Charter provides that, with certain exceptions, actions of City commissions and boards ("Board Action"), including the Board, do not become final until five consecutive City Council meetings convened in regular session have passed or a waiver of such period is granted by City Council. During those five City Council meetings (unless the waiver of such period has been granted), the City Council may, on a two-thirds vote, take up the Board Action. If the Board Action is taken up, the City Council may approve or veto the Board Action within 21 calendar days of taking up the Board Action. If the City Council takes no action to assert jurisdiction over the Board Action during those five meetings, the Board Action becomes final at the end of such period.

Board of Water and Power Commissioners

Under the Charter, the Board is granted the possession, management and control of the Power System. Pursuant to the Charter, the Board also has the power and duty to make and enforce all necessary rules and regulations governing the construction, maintenance, operation, connection to and use of the Power System and to acquire, construct, extend, maintain and operate all improvements, utilities, structures and facilities the Board deems necessary or convenient for purposes of the Department. The Mayor of the City appoints, and the City Council confirms the appointment of, members of the Board. The Board is traditionally selected from among prominent business, professional and civic leaders in the City. The members of the Board serve with only nominal compensation. Certain matters regarding the administration of the Department also require the approval of the City Council.

The Board is composed of five members. The current members of the Board are:

RICHARD KATZ, *President*. Mr. Katz was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 22, 2024. Mr. Katz was elected President of the Board on March 26, 2024. Mr. Katz is a long-time public servant and state policymaker with specific expertise in the areas of water, transportation, land use, and energy. He is the owner of Richard Katz Consulting Inc., a public policy and government relations firm based in Los Angeles. Mr. Katz previously served in the California State Assembly representing the North and East San Fernando Valley for sixteen years. After leaving the State Assembly, Mr. Katz was appointed to the State Water Resources Control Board, where he served for six years, occupying the water quality seat. Mr. Katz also served as a Senior Advisor on Energy and Water issues to Governor Gray Davis. He has previously served on the governing boards of the Los Angeles County Metropolitan Transportation Authority and Metrolink. Mr. Katz holds a Bachelor of Arts degree in political science (major) and history (minor) from San Diego State University.

GEORGE MCGRAW, *Vice President*. Mr. McGraw was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on June 20, 2023. Mr. McGraw was elected Vice President of the Board on March 26, 2024. Mr. McGraw serves as founder and CEO of DigDeep, the only water, sanitation and hygiene organization solely focused on the United States, developing education, research and infrastructure programs aimed at extending the human right to clean running water to every American. In this capacity, Mr. McGraw works with local government officials, policymakers and utility providers to innovate solutions to the problems of water and sanitation access in different areas of the nation. Mr. McGraw is an Ashoka Fellow, a member of the Aspen Global Leadership Network and former Social Entrepreneur in Residence at Stanford University. He holds a Master of Arts degree in International Law and the Settlement of Disputes from the United Nations University for Peace.

NURIT KATZ, *Commissioner*. Ms. Katz was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on December 6, 2022. She is the Chief Sustainability Officer for the University of California, Los Angeles ("UCLA"), where she has led the development of the University's first comprehensive sustainability plan and fosters collaboration across the leading public university to advance sustainability through education, research, operations, and community partnerships. For six years Ms. Katz also served as Executive Officer for Facilities Management at UCLA. She has over 15 years of teaching experience and is an Instructor for the UCLA Extension Sustainability Certificate Program. Ms. Katz also has taught for the UCLA Institute of Environment and Sustainability and prior to UCLA worked in environmental and outdoor education. She holds a Master of Business Administration degree and a master's degree in public policy from UCLA, and a Bachelor of Arts in environmental education from Humboldt State University. She is currently pursuing a PhD in ecology and evolutionary biology at UCLA and is a Trainee in the National Science Foundation Research Traineeship Innovation at the Nexus of Food, Energy, and Water Systems program.

MIA LEHRER, *Commissioner*. Ms. Lehrer was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on October 21, 2020. Ms. Lehrer is president and founder of Studio-MLA, a landscape architecture, urban design, and planning practice dedicated to advocacy by design with a vision to improve quality of life through landscape. She has served as an advisor to numerous public agencies, including the United States Fine Arts Commission under President Barack Obama, the Los Angeles Cultural Heritage Commission, and the Los Angeles Zoning Advisory Committee. Ms. Lehrer was a member of the team that delivered the Los Angeles River Revitalization Master Plan and the 2020 Upper Los Angeles River and Tributaries Master Plan. She also serves on the board for the Southern California Development Forum and in 2010 she was elevated to Fellow of the American Society of Landscape Architects. Ms. Lehrer holds a Bachelor of Arts degree from Tufts University and a Master of Landscape Architecture degree from the Harvard University Graduate School of Design.

WILMA J. PINDER, *Commissioner*. Ms. Pinder was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 8, 2024. Ms. Pinder is a former Los Angeles Assistant City Attorney. She served the city as a civil litigator and trial attorney for 30 years, 20 of those years were with the Water and Power Division of the City Attorney's Office. Ms. Pinder has been active with national, state and local bar associations, serving as a Board member on several. Ms. Pinder is a Life Fellow of the American Bar Foundation ("ABF") and served on its Board for 10 years. The ABF expands knowledge and advances justice through research on law and legal institutions. She has also served on alumni boards at the University of Southern California ("USC") and UCLA. Ms. Pinder is active in the greater Los Angeles area with a number of service-oriented groups. Ms. Pinder holds a Bachelor of Arts degree in psychology from USC, a Master of Science degree in psychology from Howard University, and a Juris Doctorate from UCLA School of Law. She is also trained in community mediation and dispute resolution.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. The management structure of the Department consists of three functional senior executive positions: Chief Operating Officer, Senior Assistant General Manager of the Power System and Chief Financial Officer. The Department's financial affairs are supervised by the Chief Financial Officer. The Power System is directed by the Senior Assistant General Manager of the Power System with an Executive Director for Construction, Maintenance and Operations, and an Executive Director for Planning, Engineering, and Technology Applications. Legal counsel is provided to the Department by the Office of the City Attorney of the City of Los Angeles.

Below are brief biographies of the Department's General Manager, Mr. Martin L. Adams, and other members of the senior management team for the Power System:

MARTIN L. ADAMS, *General Manager and Chief Engineer*. Mr. Adams was named Interim General Manager of the Department in July 2019 and confirmed as the General Manager and Chief Engineer by the City Council in September 2019. Prior to his appointment as General Manager, Mr. Adams served as the Chief Operating Officer of the Department since September 2016. In that capacity, he oversaw the Water System and Power System, along with other support organizations within the Department. Mr. Adams has more than 39 years of experience at the Department, where he started as an entry level engineer in the Water System, eventually leading the Water System as its Senior Assistant General Manager. During the course of his career, Mr. Adams worked throughout the Water System and was directly involved with the planning and implementation of major changes to water storage, conveyance, and treatment facilities to meet new water quality regulations. He has spent almost half of his career in system operations, including ten years as the Director of Water Operations in charge of the day-to-day operation and maintenance of the Los Angeles water delivery system, including the Los Angeles Aqueduct and other supply sources, pump stations, reservoirs, water treatment, and management of Water System properties. Mr. Adams received his Bachelor of Science degree in civil engineering from Loyola Marymount University in Los Angeles.

Mr. Adams has announced his retirement, which is expected to occur in the first half of 2024. The Mayor has announced that a nationwide recruitment process is being undertaken by the City for a successor General Manager. It is anticipated that Mr. Adams will continue to serve the Department while the City's recruitment process is ongoing until a successor is named.

ARAM BENYAMIN, *Chief Operating Officer*. Mr. Benyamin was named Chief Operating Officer of the Department in November 2022. In this role he oversees the Water System and Power System, along with other support organizations within the Department. Prior to rejoining the Department in November 2022, Mr. Benyamin was the Chief Executive Officer for Colorado Springs Utilities (a municipally-owned utility). He joined Colorado Springs Utilities in 2015 as the General Manager – Energy Supply and was named Chief Executive Officer in October 2018. Prior to joining Colorado Springs Utilities, Mr. Benyamin was the Department's Senior Assistant General Manager – Power System. Mr. Benyamin previously worked for the Department in various roles for over 30 years. He is a Professional Engineer with a Bachelor of Science degree in engineering from California State University, Los Angeles. Mr. Benyamin also has a master's degree in business administration from the University of La Verne and a master's degree in public of administration from California State University, Northridge.

ANN M. SANTILLI, *Chief Financial Officer*. Ms. Santilli was named Chief Financial Officer of the Department in May 2019. She had served as Interim Chief Financial Officer of the Department since March 2018. Prior to her appointment as Interim Chief Financial Officer, Ms. Santilli served as Assistant Chief Financial Officer and Controller of the Department from 2012 through February 2018 and previously held the role of Interim Chief Financial Officer of the Department from October 2010 through January 2012. Prior to her first service as Interim Chief Financial Officer, Ms. Santilli served as Chief Accounting Employee and Assistant Chief Financial Officer and Controller of the Department. She assumed the post as Controller in March 2008, as Assistant Chief Financial Officer in April 2008 and as Chief Accounting Employee in July 2010. Prior to being appointed as the Controller, Ms. Santilli was the Manager of Financial Reporting since 2003. Ms. Santilli has over 36 years of accounting and auditing experience. Ms. Santilli holds a bachelor's degree in business administration from California State University, Northridge and is a certified public accountant in the State and a certified internal auditor.

SIMON ZEWDU, *Senior Assistant General Manager of the Power System*. Mr. Zewdu assumed his current position as Senior Assistant General Manager of the Power System in October 2023 after serving as Interim Senior Assistant General Manager of the Power System since April 2023. Mr. Zewdu has over 24 years of experience with the Department and the City of Los Angeles, with duties spanning from substation design, project management, strategic planning, contracts, operations, and special projects. Prior to his current role, Mr. Zewdu led the Department's compliance with mandatory federal North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability standards including the Department's regulatory reporting obligations to State regulatory agencies. Mr. Zewdu also led the LA100 Equity Strategies Study in collaboration with the National Renewable Energy Laboratory (the "NREL") and UCLA. Over the years, Mr. Zewdu led the Department's transmission planning efforts to fulfill the Department's obligations as a transmission provider and managed the transmission engineering team responsible for the design of the Department's extra-high voltage overhead and underground transmission projects to support the reliability and resiliency of the Department's electric grid. Mr. Zewdu holds a bachelor's degree in electrical and computer engineering and a master's degree in business administration in finance.

KATHY M. FONG, *Assistant Chief Financial Officer and Controller*. Ms. Fong was named Assistant Chief Financial Officer and Controller of the Department in March 2020 after serving as the Acting Assistant Chief Financial Officer and Controller of the Department since March 2018. Ms. Fong previously served as Assistant Controller – Financial Reporting of the Department from August 2014 through February 2018 and held the role of Manager of Financial Reporting of the Department from June 2008 through July 2014. Prior to being appointed as the Manager of Financial Reporting in 2008, Ms. Fong served as the Assistant to the Manager of the Budget Office since 2002. Ms. Fong has over 34 years of accounting and budgeting experience. Ms. Fong holds a bachelor's degree in business administration with an option in accounting from California State University, Los Angeles and is a certified public accountant in the State and a certified management accountant.

PETER HUYNH, *Assistant Chief Financial Officer and Treasurer; Assistant Auditor*. Mr. Huynh was named Assistant Chief Financial Officer and Treasurer of the Department in October 2020 and Assistant Auditor of the Department in February 2021. Prior to his appointment as Assistant Chief Financial Officer and Treasurer, Mr. Huynh served as the Assistant Director of Finance and Risk Control Division of the Department since July 2006. He has over 34 years of financial management experience in debt management, risk control, financial planning, accounting, and auditing. Mr. Huynh holds a bachelor's degree in art and a certificate in accountancy from the California State University, Los Angeles. He also has a master's degree in business administration from Pepperdine University. Mr. Huynh is a certified public accountant in the State, a certified management accountant, and a chartered global management accountant.

Employees

As of January 31, 2024, the Department assigned approximately 5,234 Department employees to the Power System on a full time basis. Approximately 3,938 additional Department employees support both the Power System and the Water System on a shared basis.

The Department conducts personnel functions in accordance with the Charter-established civil service system (the "Civil Service System") applicable to most Department employees. In accordance with the Civil Service System, the Department makes appointments on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and 18 other management positions are specifically exempted from the Civil Service System.

The City Council approves the wages and salaries paid to all Department employees. In accordance with State law (the Meyers-Milias-Brown Act) and a conforming City ordinance (the Employee Relations Ordinance), the Department recognizes 14 bargaining units of Department employees. Five labor or professional organizations represent these employees' bargaining units. In the bargaining process the Department and the labor or professional organizations develop memoranda of understanding which set forth wages, hours, overtime and other terms and conditions of employment.

The International Brotherhood of Electrical Workers ("IBEW") represents more than 90% of the Department's employees through ten bargaining units. The Department's ten memoranda of understanding with IBEW have a term which commenced on October 1, 2022 and which expire on September 30, 2026.

The Department's memoranda of understanding with the Management Employees Association, Load Dispatchers Association, and Association of Confidential Employees, expire on December 31, 2025. The Department's memorandum of understanding with the Service Employees International Union, Security Unit, expired on September 30, 2022. The Department is currently in negotiations with the Service Employees International Union, Security Unit. All employment terms of the expired memorandum of understanding continue until a successor contract is executed. Since the advent of collective bargaining in 1974, work stoppages have been rare, occurring in 1974, 1981 and 1993.

Retirement and Other Benefits

Retirement, Retiree Medical, Disability and Death Benefit Insurance Plan. The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability, and Death Benefit Insurance Plan is a retirement system of employee benefits and includes the Water and Power Employees' Retirement Fund (the "Retirement Plan"), which is more fully described in "Note (13) Retirement Plan" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Retirement Plan are shared by the Power System and the Water System, with the Power System being responsible for approximately 67% of Retirement Plan costs. Since Fiscal Year 2014-15, the assumed rate of investment return on the Retirement Plan's assets has been incrementally decreased from 7.75% to 6.50%. Most recently, effective July 1, 2022, the Retirement Board lowered the assumed rate of return from 7.00% to 6.50%. A decrease in the assumed rate of return will generally contribute to an increase in the Department's required contributions to the Retirement Plan, including the Power System's share. The budgeted contributions for the Fiscal Year ending June 30, 2024 take into account this change in the discount rate. Investment return assumptions are determined through the Retirement Plan's Experience Study, which was most recently published on May 20, 2022.

As more fully described in Note 13(d), the Power System made contributions to the Retirement Plan of approximately $249 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $369 million), and the Power System made contributions to the Retirement Plan of approximately $218 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $325 million). For the Fiscal Year ending June 30, 2024, the Department has budgeted a contribution of approximately $304 million from the Power Revenue Fund to the Retirement Plan (as part of a total Department contribution of approximately $447 million).

The Department also has made, and will continue to make in the future, contributions to the Plan from the Water Revenue Fund.

The Department follows the provisions of Governmental Accounting Standards Board ("GASB") Statement No. 68, *Accounting and Financial Reporting for Pension – an amendment of GASB Statement No. 27* ("GASB No. 68"). GASB No. 68 requires employers with pension liabilities to disclose the net pension liability along with deferred inflows and outflows of resources related to the pension liability. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 68 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" of the Department's Power System Financial Statements. Specifically, see Note 6(f) for a discussion of the Power System's establishment of the regulatory asset discussed above.

According to the latest actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 22, 2023, as of July 1, 2023, the market value of the assets in the Retirement Plan was approximately $16.4 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $582.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $16.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $411.5 million. As of July 1, 2023, the Retirement Plan had unrecognized investment losses of approximately $171.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2023 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2023-24 would increase from approximately 31.4% of total Department covered payroll to 32.6% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2023 would decrease from approximately 97.6% to 96.6%.

According to the actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 23, 2022, as of July 1, 2022, the market value of the assets in the Retirement Plan was approximately $15.5 billion, which would result in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $616.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $15.8 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $318.0 million. As of July 1, 2022, the Retirement Plan had unrecognized investment losses of approximately $298.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2022 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2022-23 would increase from approximately 29.8% of total Department covered payroll to approximately 32.2% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2022 would decrease from approximately 98.0% to approximately 96.2%.

Contribution requirements for the Fiscal Year ending June 30, 2024 are set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities and future pension costs. However, the Retirement Plan uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retirement benefits, requires the employee to contribute a higher percentage of pay to the Retirement Plan, and ends the reciprocity agreement with the City's retirement plan. The Coalition of L.A. City Unions, whose members are not employed at the Department, has challenged the ending of the reciprocity agreement. The City is defending the challenge against the decision to end the reciprocity agreement. The outcome of the challenge to the end of the reciprocity agreement is not expected to have a material adverse impact on the Department or the Retirement Plan. According to a study of the proposed benefits of Tier 2, which was completed by The Segal Company on October 24, 2013, the estimated amount of contribution required to fund the benefit allocated to the current year of service (the "Normal Cost"), as a percentage of payroll, was 5.61% for Tier 2 (as compared to 16.35% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $877 million over 30 years (based on the 7.75% assumed rate of investment return on the Retirement Plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on September 22, 2023, the estimated contribution for Fiscal Year 2023-24 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, was 11.29% for Tier 2 (as compared to 21.12% for Tier 1). As of the July 1, 2023 actuarial valuation report, 53% of active Department members were covered under Tier 2.

Other Postemployment Benefits ("OPEB"). The Department provides certain healthcare benefits (the "Healthcare Benefits") and death benefits to active and retired employees and their dependents. These OPEB Benefits are more particularly described in "Note (14) Other Postemployment Benefits Plans" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Healthcare Benefits are shared by the Water System and the Power System, with the Power System historically being responsible for approximately 67% of the costs of the Healthcare Benefits. As more fully described in Note (14), the Power System paid Healthcare Benefits of approximately $75.9 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $113.2 million), and the Power System paid Healthcare Benefits of approximately $73.7 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $110.8 million). For the Fiscal Year ending June 30, 2024, the Department has budgeted approximately $78.3 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $118.7 million).

The Department also has paid, and will continue to pay in the future, Healthcare Benefits from the Water Revenue Fund, for the Water System's Healthcare Benefits costs.

According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, as of June 30, 2023, the market value of the assets of the Healthcare Benefits was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $345.8 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $371.7 million. As of June 30, 2023, the Healthcare Benefits had unrecognized investment gains of approximately $25.9 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2023, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 106.84% as of June 30, 2022 to 114.16% as of June 30, 2023. On a market value of assets basis, the funded ratio increased from 104.95% as of June 30, 2022 to 113.17% as of June 30, 2023. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $180.0 million as of June 30, 2022 to a surplus of $371.7 million as of June 30, 2023.

According to the actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 16, 2022, as of June 30, 2022, the market value of the assets of the Healthcare Benefits was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $130.3 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $180.0 million. As of June 30, 2022, the Healthcare Benefits had unrecognized investment gains of approximately $50.0 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2022, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 101.15% as of June 30, 2021 to 106.84%. On a market value of assets basis, the funded ratio decreased from 113.58% as of June 30, 2021 to 104.95% as of June 30, 2022. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $29.6 million as of June 30, 2021 to a surplus of $180.0 million as of June 30, 2022.

Contribution requirements for the Fiscal Year ending June 30, 2024 are set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities for Healthcare Benefits and future contribution requirements. However, the Healthcare Benefits uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

For a schedule that provides information about the Department's overall progress made in accumulating sufficient assets to pay Healthcare Benefits when due, prior to allocations to the Power System and the Water System, see the "Required Supplementary Information" of the Department's Power System Financial Statements.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retiree healthcare benefits. According to a study of the proposed OPEB for Tier 2 employees of the Department, which was completed by The Segal Company on November 8, 2013, the estimated Normal Cost, as a percentage of payroll, was 2.63% for Tier 2 (as compared to 4.33% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $136.5 million over 30 years (based on the 7.75% assumed rate of investment return on the OPEB plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, for Fiscal Year 2023-24, the Normal Cost, as a percentage of payroll, was estimated to be 4.36% for Tier 2 (as compared to 4.77% for Tier 1).

Effective July 1, 2017, the Department follows the provisions of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, an amendment of GASB Statement No. 45 ("GASB No. 75"). GASB No. 75 requires employers with other postemployment liabilities to disclose the net postemployment liability along with deferred inflows and outflows of resources related to the other postemployment liability. The Department adopted the provisions of GASB No. 75 beginning for the Fiscal Year ended June 30, 2018. Accordingly, the cumulative effect of the impact on net position as of July 1, 2017 was negative $661.2 million. As of June 30, 2023, the Power System had a net OPEB liability surplus of $11.8 million comprised of $87.4 million surplus of retiree medical and $75.6 million liability in death benefits. As of June 30, 2022, the Power System had a net OPEB liability surplus of $172.6 million comprised of $235.7 million surplus of retiree medical and $63.1 million liability in death benefits. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 75 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" in the Department's Power System Financial Statements. Specifically, see Note 6(g) for a discussion of the Power System's establishment of the regulatory asset discussed above.

Transfers to the City

Pursuant to the Charter, the City Council may, subject to the provisions of contractual obligations, direct a transfer of surplus money in the Power Revenue Fund to the City's reserve fund (a "Power Transfer") with the consent of the Board. The Board may withhold its consent if it finds that making the Power Transfer would have a material adverse impact on the Department's financial condition in the year the Power Transfer is to be made. In the event the Board does not approve any year's Power Transfer, the City Administrative Officer is to verify the Department's findings and make a report thereon and recommendations with respect thereto. After receiving such report, and in consultation with the City Council and the Mayor, the Board shall either amend or uphold its preliminary findings.

Pursuant to covenants contained in the Master Resolution, a Power Transfer may not exceed the net income of the prior Fiscal Year or reduce the Power System's surplus to less than 33-1/3% of total Power System indebtedness. Subject to the restrictions of the Charter and the Master Resolution, the Board has most recently approved transfers totaling $244,695,000 to the City during the Fiscal Year ending June 30, 2024. Such transfers are expected to be made in full prior to the end of Fiscal Year 2023-24.

The following table shows the amounts of the Power Transfer in each of the last five Fiscal Years:

POWER TRANSFERS
FOR FISCAL YEARS ENDED JUNE 30, 2019 – 2023
($ in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2019	$232,557
2020	229,913
2021	218,355
2022	225,015
2023	232,043

Source: Department of Water and Power of the City of Los Angeles.

The City does not include any funds in the Power Transfer that the Department collects pursuant to the Electric Rates established under the Incremental Electric Rate Ordinance, which was adopted in 2016. However, the Power Transfer includes surplus revenue generated from Electric Rates established under the Rate Ordinance adopted in 2008. Starting in Fiscal Year 2017-18, the Power Transfer is approximately 1.01 cents for every kWh sold to retail electric customers.

Insurance

The Department's insurance program currently consists of a combination of commercial insurance policies, a wildfire Catastrophe Bond ("CAT Bond") and self-insurance. All general liability claims within the Department's self-insured retention are administered under the Department's self-insurance program and the Department carries commercial excess general liability insurance above its self-insured retention. There are two separate towers of insurance. The first is for non-wildfire losses. After meeting the $3 million retention, the program has a primary layer of $35 million, which includes 50% of co-insurance for the 2024-25 policy year (April 2024 to April 2025). Co-insurance is a designated percentage of the policy that is retained by the Department and the remaining policy amount is recoverable from the insurer. Above the primary layer of $35 million are additional layers of commercial liability insurance that provide an additional $125 million of coverage, which has no co-insurance and would provide coverage up to the policy limits. The total limit available for non-wildfire losses is $160 million. There is a second tower of insurance that is solely for wildfire losses. The Department has a total of $50 million in self-insured retention that serves as its primary layer for wildfire coverage and above that primary self-insurance retention layer, the Department has procured an additional $115.5 million of commercial wildfire insurance, totaling an insurance tower of $165.5 million. To complement its overall wildfire insurance program, the Department has further provided for $31.5 million of wildfire coverage through a CAT Bond. The $31.5 million indemnity wildfire CAT Bond, which is for the three-year period September 2021 to September 2024, has an attachment point at $125 million and is intended to cover a portion of any large claim that might exceed the self-insurance and commercial insurance coverage. CAT Bonds are multi-year issuances and pay out based on a catastrophic fire event that occurs within the three-year period of the specific bond. CAT Bonds allow the Department to obtain additional wildfire coverage capacity outside of a commercial insurance policy, but, unlike commercial insurance, the Department achieves a premium cost that is fixed and known for the three-year period of the bond. Through the utilization of commercial insurance, the CAT Bond and self-insurance, the wildfire insurance program has a total limit of $197 million available for wildfire losses.

For discussion regarding liability issues as they relate to wildfire losses, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

Going forward, including following the expiration of the coverage period for the existing CAT Bond issuance, the Department will continue to consider any available coverage options in the market in order to ensure that the Department is adequately protected against catastrophic liability events and wildfires. In addition to the excess general liability insurance programs and the existing CAT Bond issuance, the Department continues to maintain a bona fide program of self-insurance as well. As of December 31, 2023, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $222.5 million in a restricted cash account. The Power Revenue self-insurance fund is specific to the Power Division and is primarily designed to cover a large catastrophic event that could affect the Power Division operations (*e.g.*, liability for a large wildfire). The Department annually reviews the amount retained for self-insurance and may adjust such amount if it deems such adjustment appropriate.

The Department has purchased a primary cyber insurance policy, with a self-insured retention component. This insurance policy covers certain types of cyber incidents and provides reimbursement coverage for costs to respond to data privacy or security incidents and for expenses incurred in connection with the investigation, prevention, and resolution of any cyber threat.

The Department commercially insures its physical plant through a policy of all risk property insurance, which is written on a replacement cost-basis. The policy covers all risk of physical loss or damage to buildings, structures, auxiliary and main plant equipment. Such insurance has a policy loss limit of $500 million for all claims in a single policy year. The all-risk property insurance has a deductible of $5 million. The Department has secured earthquake coverage and sudden and accidental pollution coverage as part of its all-risk property insurance program.

The Department's physical plant coverage does not provide coverage in certain events including terrorism or war. However, the Department has purchased a Terrorism Limits and Terrorism Risk Insurance Extension Act of 2005 ("TRIEA") Endorsement (the "Endorsement") to its excess general liability coverage under which coverage is extended to cover losses resulting from certain acts certified by the Secretary of the U.S. Department of the Treasury to be an act of terrorism, as defined in TRIEA. Currently, from 2002 through December 31, 2027, the Endorsement limits insurers liability for losses resulting from certified acts of terrorism when the amount of such losses exceeds $100 billion in any one calendar year. If the aggregate insured losses for all insurers exceed $100 billion, the Department's coverage may be reduced.

As a participant in the Palo Verde Nuclear Generating Station ("PVNGS") and associated transmission systems, the Department is an additional named insured on various forms of insurance providing protection against property and liability losses relating to such facilities. The amounts of coverage are established by participating owners and procured by the operating agent for the facility.

The Department, as the operating agent for the Intermountain Power Project ("IPP"), the Mead-Adelanto Transmission Project, the Pacific DC Intertie and in connection with its relationships with other entities and agencies, includes other entities or agencies as additional named insureds on the various forms of insurance procured for such facilities.

The Department continuously evaluates its insurance program and may modify the current configuration of commercial insurance and self-insurance with respect to the Power System. Insurance limits maintained by the Department are subject to change depending on market conditions and assessments by the Department as to risk exposure. The utilization of commercial insurance along with alternative risk options such as CAT Bonds allows the Department to strengthen its overall risk management program as well as provide flexibility in setting and adjusting its self-insurance retention limits as part of the continual review of the Department's insurance budget.

Investment Policy and Controls

Department's Trust Funds Investment Policy. The majority of the Power System funds are held in the Power Revenue Fund, investments of which are managed by the Office of Finance of the City. The funds have been invested as part of the City's investment pool program since 1983. Certain financial assets of the Department that are held in special-purpose trust or escrow funds with an independent trustee ("Trust Funds") more fully described in "Note (7) Cash, Cash Equivalents, and Investments" of the Department's Power System Financial Statements ("Note 7"), are not included in the City's investment pool program. The Department manages the investment of the Trust Funds in which approximately $694.5 million (investments at fair market value) was on deposit as of December 31, 2023. The Department's investment of such funds complies with the California Government Code in all material respects and such funds are invested according to the Department's Trust Funds Investment Policy (the "Trust Funds Investment Policy"), which sets forth investment objectives and constraints. For more information about the Trust Funds Investment Policy, see Note 7. Such funds consist of debt reduction trust funds, the nuclear decommissioning trust funds, the natural gas trust fund, the California Independent System Operating Markets trust fund, and the hazardous waste treatment storage and disposal trust fund. These trust funds are being held by U.S. Bank Trust Company, National Association as trustee/custodian. Amounts in the debt reduction trust fund are to be applied at the discretion of the Chief Financial Officer, to the retirement (including the payment of debt service, purchase, redemption and defeasance) of Power System debt, including obligations to Intermountain Power Agency ("IPA") and Southern California Public Power Authority ("SCPPA"). As of December 31, 2023, the debt reduction trust fund had a balance of approximately $505.8 million (investments at fair market value as of such date).

Under the Trust Funds Investment Policy, the Department's investment program seeks to accomplish three specific goals: (i) preserve the principal value of the funds, (ii) ensure that investments are consistent with each individual fund's liquidity needs and (iii) achieve the maximum yield/return on the investments.

The overall responsibility for managing the Department's investment program for the Trust Funds rests with the Department's Chief Financial Officer, who directs investment activities through the Department's Assistant Chief Financial Officer and Treasurer. An Investment Committee, comprised of the City Controller, a Board member designated by the Board President, the General Manager and the Department's Chief Financial Officer (the "Department Investment Committee") is charged with oversight responsibility. The Trust Funds Investment Policy is adopted by the Board from time to time, and fund activity is reviewed periodically by the Department Investment Committee to ensure its consistency with the overall objectives of the policy, as well as its relevance to current law and financial and economic trends.

The Department's Assistant Chief Financial Officer and Treasurer or its designee reviews all investment transactions for the Trust Funds on a monthly basis for control and compliance and submits quarterly investment reports that summarize investment income to the Department Investment Committee, the Board and the Mayor for information and evaluation.

POWER SYSTEM TRUST FUNDS INVESTMENTS
ASSETS AS OF DECEMBER 31, 2023
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Government Securities	$ 35,521
U. S. Sponsored Agency Issues	313,419
Supranationals	12,876
Medium term corporate notes	149,505
Municipal obligations	52,953
California state bonds	12,221
Other state bonds	39,130
Commercial paper	199
Certificates of deposit	40,225
Money market funds	38,415
Total	$694,464

Source: Department of Water and Power of the City of Los Angeles.
* Totals may not equal sum of parts due to rounding.

Department Financial Risk Management Policies. In order to manage certain financial and operational risk, the Board has adopted a number of policies in addition to its Trust Funds Investment Policy. The Board has adopted a Counterparty Evaluation Credit Policy designed to minimize the Department's credit risk with its counterparties. This policy applies to wholesale energy, transmission, physical natural gas and financial natural gas transactions entered into by the Department. Pursuant to this policy the Department assigns credit ratings to such counterparties. The policy requires the use of standardized netting agreements which require such counterparties to net positive and negative exposures to the Department and requires credit enhancement from counterparties that do not meet an acceptable level of risk. Sales to such counterparties are only permitted up to the amount of purchases with a netting agreement and, in certain cases, credit enhancement in place.

The Board has adopted a Retail Natural Gas Risk Management Policy designed to mitigate the Department's exposure to unexpected spikes in the price of natural gas used in the production of electricity to serve retail customers. This policy authorizes Department management to enter into transactions for natural gas subject to specified parameters, such as duration of contract and price and volumetric limits. It also establishes internal controls for natural gas risk management activity. See "THE POWER SYSTEM – Fuel Supply for Department-Owned Generating Units and Apex Power Project."

The Board has adopted a Wholesale Marketing Energy Risk Management Policy to establish a risk management program designed to manage the Department's exposure to risks resulting from purchases and sales of wholesale energy, transmission services and ancillary services. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types and establishes internal controls for wholesale energy risk management activity.

The Board has adopted an Environmental Credit and Renewable Energy Credit Policy to establish a risk management program that is designed to manage the Department's exposure to risks resulting from purchases and sales of emissions credits or allowances and other credits available for the purpose of compliance with environmental laws, rules, and regulations. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types, and establishes internal controls surrounding credit risk management activity.

The Board has adopted a Dodd-Frank Act Compliance Policy to ensure the Department complies with applicable provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and commodity futures trading commission requirements.

City Investment Policy. The Office of Finance of the City invests temporarily idle cash on behalf of the City, including that of the proprietary departments, such as the Department, as part of a pooled investment program. As of December 31, 2023, the Power System had approximately $1.58 billion of unrestricted cash and approximately $1.56 billion of restricted cash on deposit with the City. This month-end amount does not reflect the GASB Statement No. 31 fair market value adjustment. For information regarding the fair market value adjustment of the Department's pooled investment fund assets as of June 30, 2023, see Note 7(b) in the Department's Power System Financial Statements. This amount is in addition to what is on hand in the Trust Funds, see "– *Department's Trust Funds Investment Policy*" above. The City's pooled investment program combines general receipts with special funds for investment purposes and allocates interest earnings and losses on a pro-rata basis when the interest is earned and distributes interest receipts based on the previously established allocations. The primary responsibilities of the Office of Finance of the City and the pooled investment program are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. Funds invested by the Power System in the pooled investment program are available for withdrawal within five business days without penalties. In addition, 20% of the pool, as of June 30, 2023, had maturities less than one month and 39% of the pool, as of June 30, 2023, had maturities of one year or less.

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CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2023
(Dollars in Thousands)
(Unaudited)

	Amount	Percent of Total	Power System Share
U.S. Treasury Notes	$ 8,939,146	58.52%	$ 1,591,211
Commercial Paper	987,939	6.47	175,925
Medium-Term Notes	1,709,101	11.19	304,266
U.S. Agencies Securities	1,918,910	12.56	341,517
Supranationals	219,575	1.44	39,155
Short-Term Investment Funds	1,134,771	7.43	202,028
Asset-Backed Securities	305,709	2.00	54,382
Securities Lending Short-Term Repurchase Agreement	59,668	0.39	10,604
Negotiable Certificates of Deposit	0	0.00	0
Total General and Special Pools*	**$15,274,819**	**100.00%**	**$2,719,088**

Source: Department of Water and Power of the City of Los Angeles and Los Angeles City Treasurer.

Note: Department funds held by the City are both unrestricted and restricted funds. Totals may not equal sum of parts due to rounding.

Note: Fair Market Value as of June 30, 2023.

The City's investment operations are managed in compliance with the California Government Code and the City's statement of investment policy, which sets forth permitted investments, liquidity parameters and maximum maturity of investments. The investment policy is reviewed and approved by the City Council on an annual basis.

Monthly reports of investment activity are presented to the Mayor, the City Council and the Department to indicate, among other things, compliance with the investment policy. The City's Office of Finance does not invest in structured and range notes, securities that could result in zero interest accrual if held to maturity, variable rate, floating rate or inverse floating rate investments or mortgage-derived interest or principal-only strips.

The investment policy permits the City's Office of Finance to engage custodial banks to enter into short-term arrangements to lend securities to various brokers. Cash and/or securities (United States Treasuries and Federal Agencies only) collateralize these lending arrangements, the total value of which is required to be at least 102% of the market value of securities loaned out. The securities lending program is limited to a maximum of 20% of the market value of the City's Office of Finance's pool by the City's investment policy and the California Government Code.

For more information about the investments in the City's Office of Finance pool, see Note 7.

ELECTRIC RATES

Rate Setting

Pursuant to the Charter, the Board, subject to the approval of the City Council by ordinance (as discussed below), fixes the rates for electric service from the Power System ("Electric Rates"). The Charter provides that the Electric Rates shall be fixed by the Board from time to time as necessary. The Charter also provides that the Electric Rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied and the value of the service provided. The Charter further provides that rates for electric energy may be negotiated with individual customers, provided that such rates are established by binding contract, contribute to the financial stability of the Power System and are consistent with such procedures as the City Council may establish.

The Board is obligated under the Charter and the rate covenant in the Master Resolution to establish Electric Rates and collect charges in amounts which, together with other available funds, shall be sufficient to service the Department's Power System indebtedness and to meet the Power System's expenses of operation and maintenance. The Charter provides that Electric Rates are subject to the approval of the City Council by ordinance (a "Rate Ordinance"). The Charter further requires that the City Council approve Rate Ordinances for the Electric Rates prescribed in the rate covenant in the Charter, which rate covenant is also included in the Master Resolution.

The Department's completed interim rate review of the last rate action for Fiscal Year 2015-16 through Fiscal Year 2019-20 resulted in planned annual system average Electric Rate increase adjustments. The average yearly increase during the five-year period was approximately 4.5% for low-energy users, approximately 4.0% for midrange users, and approximately 5.5% for top tier users, reflected in increased actual pass-through cost adjustments and decreased Base Rate revenue targets.

The rate increase over these five Fiscal Years is reflected in the Incremental Electric Rate Ordinance and as a result, effective April 15, 2016, the Department's retail electric revenue requirement has been funded from the Rate Ordinance adopted in 2008 and the Incremental Electric Rate Ordinance through the following major components:

(a) Under the Rate Ordinance adopted in 2008:

(i) Base Rates: Base Rates are used to fund expenditures including debt service arising from capital projects (except projects relating to the Renewable Portfolio Standard ("RPS")), operational and maintenance expenses (except as RPS-related), public benefit spending, property tax, and a prorated portion of the Power Transfer;

(ii) Reliability Cost Adjustment (the "RCA"): The RCA is used to recover certain power reliability expenditures; and

(iii) Energy Cost Adjustment (the "ECA"): The ECA is used to recover expenditures for fuel, non-renewable purchased power, RPS and energy efficiency-related expenditures.

(b) Under the Incremental Electric Rate Ordinance:

(i) Incremental Base Rates: The Incremental Base Rates are used to recover costs of providing electric utility service that are not recovered by Base Rates or any of the Rate Ordinance cost adjustments, including labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly-owned plants and other inflation-sensitive costs, in addition to including the Power Access Charge, which is a consumption-based tiered charge applied to residential non-Time-of-Use Residential Rate customers used to recover basic infrastructure costs for providing access to the power grid;

(ii) Incremental Reliability Cost Adjustment (the "IRCA"): The IRCA is used to recover costs associated with operations and maintenance, debt service expense of the Power System Reliability Program and RCA under-collection;

(iii) Variable Energy Adjustment (the "VEA"): The VEA is used to recover costs associated with fuel, non-renewable portfolio standard power purchase agreements, economy purchases, legacy ECA under-collection and Base Rates decoupling from energy efficiency impact;

(iv) Capped Renewable Portfolio Standard Energy Adjustment (the "CRPSEA"): The CRPSEA is used to recover costs associated with RPS operations and maintenance, debt service and energy efficiency programs; and

(v) Variable Renewable Portfolio Standard Energy Adjustment (the "VRPSEA"): The VRPSEA is used to recover costs associated with RPS market purchases and costs above any operations and maintenance and debt service payments.

The RCA, ECA, IRCA, VEA, CRPSEA and VRPSEA are pass-through cost adjustments applied by factors that the Department may change with approval of the Board, without changes to existing Rate Ordinances.

Recent Rate Actions. On the recommendation of the Office of Public Accountability (the "OPA"), the Board decreased the Base Rate revenue targets for Fiscal Year 2018-19 and Fiscal Year 2019-20 by 2% each. The OPA further recommended, and the Department supports the recommendation, to use four-year rate action cycles, rather than replicate the recent five-year rate action cycle. In June 2022, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2022-23 of 2.035%, in accordance with the provisions of the Incremental Electric Rate Ordinance. In June 2023, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2023-24 of 5.60% in accordance with the provisions of the Incremental Electric Rate Ordinance. The increase to the Base Rate revenue target will continue to provide the Department with sufficient revenues to meet the rate covenant under the Master Resolution and the Board adopted financial metrics. The Department is in the process of reviewing the Rate Ordinance and Incremental Electric Rate Ordinance and, based on current and assumed market conditions, determining what changes, if any, need to be made in connection with the next rate action. Department staff expects to propose a schedule for the next rate action to the Board in the second half of calendar year 2024.

Proposition 26. In 2010, California voters approved Proposition 26 ("Proposition 26"), an initiative measure amending Article XIII C of the State Constitution to add a new definition of "tax." Each such tax cannot be imposed, extended, or increased by a local government without voter approval. Article XIII C of the State Constitution, as amended by Proposition 26, defines "tax" to include any levy, charge, or exaction imposed by a local government, except, among other things, (a) charges imposed for benefits conferred, privileges granted, or services or products provided, to the payor (and not to those not charged) that do not exceed the reasonable costs to the local government of conferring, granting or providing such benefit, privilege, service, or product, and (b) property-related fees imposed in accordance with the provisions of Article XIII D of the State Constitution. The Department believes that the Electric Rates and charges do not constitute taxes as defined in Article XIII C of the State Constitution.

A voter initiative entitled "The Taxpayer Protection and Government Accountability Act" ("Initiative 1935") has been determined to be eligible for the November 2024 Statewide general election and, unless withdrawn by its proponent prior to June 27, 2024, or removed pursuant to the emergency petition for writ of mandate filed by the Governor of California with the California Supreme Court seeking such removal, will be certified as qualified for the ballot in such election. Were it to be adopted by the voters in the Statewide general election, Initiative 1935 would amend the California Constitution to, among other things, provide that charges for services or products provided directly to the payor (such as charges for electricity) are "taxes" subject to voter approval unless the local government can prove by clear and convincing evidence that the charge is reasonable and does not exceed the "actual cost" of providing the service or product, defined as "(i) the minimum amount necessary to reimburse the government for the cost of providing the service or the product to the payor, and (ii) where the amount charged is not used by the government for any purpose other than reimbursing that cost." If adopted, Initiative 1935 would be subject to judicial interpretation. The Department is unable to predict whether and how Initiative 1935, if adopted, would be interpreted by the courts, and there can be no assurance that any such interpretation or application would not have an adverse impact on the Department, the Power System or the revenues of the Power System.

Board Adopted Financial Planning Criteria. The Board has directed the Department to use the following criteria when preparing the Power System's financial plans with respect to Electric Rates: (i) maintain a minimum operating cash target of the equivalent of 170 days of operating expenses, (ii) maintain full obligation coverage of at least 1.7 times, and (iii) maintain a debt-to-capitalization ratio of less than 68%. These criteria are subject to reviews and adjustments from time to time by the Board with advice from the Department's financial advisors and were most recently revised on May 26, 2020.

Neighborhood Councils. Pursuant to a Memorandum of Understanding with the City's Neighborhood Councils, the Department agrees to use its best efforts to undertake a 60-day or 90-day notification and outreach period (depending on the duration of the Department's proposed rate action) prior to submitting a residential or non-residential retail business customer electric rate increase proposal involving changes to the Rate Ordinances to the Board for approval. The Neighborhood Councils have indicated they will use their best efforts to provide written input regarding such rate proposals to the Department within 60 days of receiving the above-discussed notifications.

Office of Public Accountability. Section 683 of the Charter establishes the OPA with respect to the Department. The primary role of the OPA is providing public, independent analysis to the Board and City Council about Department actions as they relate to the Electric Rates and water rates. The role of the OPA is advisory rather than as an approver of Electric Rates. The OPA is headed by an Executive Director appointed by a citizens committee, subject to confirmation by the City Council and Mayor. The Executive Director of the OPA serves as the Ratepayer Advocate for the OPA. On February 1, 2012, Dr. Frederick H. Pickel was appointed as Executive Director of the OPA (the "Ratepayer Advocate"); and on December 5, 2018, Dr. Pickel was reappointed as the Ratepayer Advocate for a five-year term. Dr. Pickel's term as Executive Director of OPA and Ratepayer Advocate expired on December 5, 2023, however, Dr. Pickel will continue to serve in those roles until his retirement, which is expected to occur in the second quarter of 2024. The rate action effective April 15, 2016 was supported by the Ratepayer Advocate following his review of the proposed rate changes. The rate action included certain changes proposed by the Ratepayer Advocate. As a result of the rate action involving the Incremental Electric Rate Ordinance for Fiscal Year 2015-16 through Fiscal Year 2019-20, the Department is required to provide semi-annual written reports each year regarding certain Board-established metrics to the Board and the OPA.

Rate Regulation

While changes in the retail Electric Rate ordinances are subject to approval by the City Council, the authority of the Board to impose and collect retail Electric Rates for service from the Power System is not subject to the general regulatory jurisdiction of the California Public Utilities Commission (the "CPUC") or any other State or federal agency. The California Public Utilities Code (the "Public Utilities Code") contains certain provisions affecting all municipal utilities such as the Power System. At this time, neither the CPUC nor any other regulatory authority of the State nor the Federal Energy Regulatory Commission ("FERC") approves the Department's retail Electric Rates. It is possible that future legislative and/or regulatory changes could subject the Department to the jurisdiction of the CPUC or to other limitations or requirements.

The California Energy Resources Conservation and Development Commission, commonly referred to as the California Energy Commission (the "CEC"), is authorized to evaluate rate policies for electric energy as related to the goals of the Warren-Alquist State Energy Resources Conservation and Development Act (Public Resources Code Section 25000 et seq.) and make recommendations to the Governor of the State, the Legislature and publicly-owned electric utilities ("POUs") such as the Department.

Although its retail Electric Rates are not subject to approval by any state or federal agency, the Department is subject to certain provisions of the Public Utilities Code and the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA applies to the purchase of the output of "qualified facilities" ("QFs") at prices determined in accordance with PURPA. The Energy Policy Act of 2005 repealed the mandatory purchase obligation for electric utilities when FERC determines that the QFs have non-discriminatory access to wholesale power markets with certain characteristics. The Department has neither applied for nor been relieved of its mandatory purchase obligation. The Department believes that it is currently operating in compliance with PURPA.

Under federal law, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise), including the Department, to provide electric transmission access to others at cost-based rates. FERC also has licensing authority over hydroelectric facilities and regulates the reliability and security of the nation's bulk power system.

With, among other things, the consent of the Department, operational control of the transmission facilities owned or controlled by the Department may be transferred to the California statewide network administered by the California Independent System Operator Corporation ("Cal ISO"). See "THE POWER SYSTEM – Transmission and Distribution Facilities." In 2017, the Department updated its Open Access Transmission Tariff ("OATT"), which included revising the cost-of-service and rate design for the Department's wholesale transmission rates. In 2020, the Department updated its OATT to facilitate entry into Cal ISO's Western Energy Imbalance Market (the "EIM"). The April 2020 amendment to the Department's OATT focused predominantly on non-rate terms and conditions related to the EIM, to ensure that services under the OATT would continue to be provided in a comparable and not unduly discriminatory or preferential manner to all of the Department's OATT customers. The April 2020 amendment largely followed similar, prior OATT amendments of other utilities already participating in the EIM. A further minor non-rate terms and conditions amendment occurred in December 2021. For more information on the Department's entry into the Western EIM, see "THE POWER SYSTEM – Transmission and Distribution Facilities."

Billing and Collections

General. With some limited exceptions, the Department currently bills residential customers on a bimonthly basis and commercial and industrial customers on a monthly basis. The Department prepares bills covering water and electric charges and non-Department charges (such as sewer services, solid waste resources fee and State and local taxes). Payments are posted in the following order: overdue receivables, customer deposits, water charges, electric charges, State and local taxes, sewer service charges, solid waste resources fees and bulky item fees. Within overdue receivables, payments received are applied in the same order for which payments are posted for current receivables.

In September 2022, the Department launched a new Level Pay system that provides eligible residential customers the opportunity to pay a monthly recurring amount for utility services based on an average of the customer's past usage and costs over the previous 12 months. Payment terms of 12, 24 and 36 months are available. At the end of the payment term, Level Pay will automatically renew and the monthly amount will be recalculated. Any underpayment or overpayment will be rolled into the calculation of the next term. The customer may cancel Level Pay at any time. It is not known at this time how many customers will ultimately sign up for Level Pay. Participation to date has been minimal but is continuing to increase. The Department does not anticipate Level Pay to have a materially adverse impact on its finances or operations.

Billing System. In September 2013, the Department launched a new customer information and billing system, designed and implemented by Pricewaterhouse Coopers LLP. Immediately following the launch of the new billing system, the Department experienced numerous billing issues in connection with the new system, including, but not limited to, (a) the inability to issue bills to customers, (b) the inability to issue accurate bills to customers, (c) an increase in estimated bills that were sent to customers where metering information was not available, and (d) the inability to generate multiple business reports, including financial reports reflecting the Department's accounts receivable. The customer information and billing system is currently being used by the Department. The Department continues to work to improve the functionality of the system to meet the Department's original expectations for the system.

Delinquencies. Based on annual historical experience of delinquencies, the Department historically has been unable to collect approximately 0.7% of the amounts billed to its customers. In light of the prior billing issues noted above and in response to the COVID-19 pandemic described below, the allowance for doubtful accounts has been increased to 2.0% of Power System sales since Fiscal Year 2020-21, creating an allowance of $280.4 million for the Fiscal Year ended June 30, 2023. The Power System's accounts receivable (including utility user's tax) as of June 30, 2023 were $1.05 billion compared to $855.7 million as of June 30, 2022. Of these amounts, $608.6 million (58.05% of total receivables) and $445.2 million (52.03% of total receivables) were 120 days or more past the payment due date as of June 30, 2023 and June 30, 2022, respectively. As of December 31, 2023, the Power System's allowance for doubtful accounts was $289.9 million and accounts receivable were $1.26 billion (including utility user's tax). Of these amounts, $734.1 million (58.36% of total receivables) were 120 days or more past the payment due date. As of December 31, 2022, the Power System's allowance for doubtful accounts was $309.7 million and accounts receivable were $1.1 billion (including utility user's tax). Of these amounts, $518.4 million (48.79% of total receivables) were 120 days or more past the payment due date.

COVID-19 Effects. In response to the COVID-19 pandemic, the Department deferred disconnection of water and power services to customers who were unable to pay their bills due to financial hardship, which deferrals officially ended on March 31, 2022 (the Department began the resumption of disconnections for commercial customers in June 2023 and is currently working on a plan to resume service disconnections for residential customers in the near future). As a result of the deferral of disconnections, the Department has experienced an increase in the amount of bills that are 120 days or more past their payment due date as described above under "Delinquencies." Ultimately, customers are still responsible to pay the billed amounts and the Department will work with customers by providing payment options. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Global Health Emergencies; COVID-19 Pandemic."

The California Legislature established the 2021 California Arrearage Payment Program ("2021 CAPP") to provide financial assistance for California energy utility customers to help reduce past due energy bill balances during the COVID-19 pandemic. Administered by the Department of Community Services and Development (the "CSD"), the 2021 CAPP dedicated approximately $994 million in federal American Rescue Plan Act funding to address Californian's energy debts, of which approximately $299 million was allocated for financial assistance to customers of POUs and electrical cooperatives. The 2021 CAPP implementation was divided into four distinct phases. During phase one, the total residential energy arrearages were quantified through a survey of energy utilities. During phase two, applications were submitted for assistance. During phase three, 2021 CAPP benefits were applied directly to eligible residential and commercial customer accounts. During phase four, required reports were submitted to the CSD to confirm the outcome of delivered 2021 CAPP benefits. The Department submitted its survey on September 3, 2021 including a funding request of approximately $203 million for residential arrearages and approximately $109 million for commercial arrearages. The Department received $202.8 million of funding of which $201.5 million have been credited towards residential arrearages. As authorized by the CSD, the Department distributed the remaining $1.3 million towards residential and commercial arrearages in March 2022.

The California Legislature established the 2022 California Arrearage Payment Program, which dedicates approximately $1.2 billion to address Californian's energy debts. The Department submitted its survey on October 19, 2022 including a funding request of approximately $76.6 million for residential arrearages. The Department received the requested funding amount and credited residential arrearages in January 2023.

Write-Off Procedures. Uncollectible accounts are recoverable by the Department by passing on such "bad debts" to the ratepayers via pass-through adjustment factors. Due to hot weather in the summer and associated higher bills and the Department's bimonthly billing process, accounts receivable balances generally increase in the late summer and autumn and generally decrease in the winter and spring. These accounts receivable balances include inactive accounts. Inactive accounts that are included in accounts receivable that cannot be linked to an active account will be written off as uncollectible.

Customer Bill of Rights. In January 2017, the Board adopted a "Customer Bill of Rights" which was developed by the Department in consultation with then Mayor Eric Garcetti and is designed to improve service for Department customers. On February 26, 2019, the Board extended the "Customer Bill of Rights" indefinitely.

THE POWER SYSTEM

General

The Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,730 megawatts ("MW") and net dependable capacity of 8,015 MW as of December 31, 2023, and properties with a net book value of approximately $13.7 billion as of December 31, 2023. The Power System's highest load registered 6,502 MW on August 31, 2017. Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department achieved its energy efficiency goal of 15% energy efficiency savings by 2020 and is now focused on a tentative projection towards an additional 3,431 gigawatt hours ("GWhs") of energy savings by 2035. For the operating statistics of the Power System, see "OPERATING AND FINANCIAL INFORMATION – Summary of Operations."

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The Department estimated that the Power System's capacity (as of December 31, 2023) and energy mix (actual numbers for calendar year 2022) were approximately as follows:

DEPARTMENT GENERATION MIX PERCENTAGES

Resource Type	Capacity Percentage(1)	Energy Percentage(2)
Natural Gas	36%	34.5%
Large Hydro	16	4.0
Coal	11	12.6
Nuclear	4	13.3
Renewables	33	35.6
Storage	<1	–
Unspecified Sources of Energy(3)	–	–
Total	100%	100%

(1) Net Maximum Unit Capability as of December 31, 2023.

(2) Energy percentage is based on the Department's calendar year 2022 fuel mix submission as part of the 2022 Annual Power Content Label (APCL) to the California Energy Commission in September 2023.

(3) Unspecified sources of energy means electricity from transactions that are not traceable to specific generation sources.

Note: Totals may not equal sum of parts due to rounding.

The Department anticipates that its generation mix will change in response to statutory and regulatory developments. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY."

Generation and Power Supply

The Power System has a number of generating resources available to it. The following discussion describes the Department's solely owned, jointly owned and contracted generation facilities, as well as fuel and water supplies and spot purchase activities. Currently, the Department's base load requirements are fulfilled primarily by generating capacity at IPP and PVNGS, and balanced with its natural gas, hydroelectric, renewable resources and spot purchases. The following information concerning the capacities of various facilities is as of December 31, 2023.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of December 31, 2023, are summarized in the following table:

DEPARTMENT OWNED FACILITIES

Type of Fuel	Number of Facilities	Number of Units	Net Maximum Capacity (MW)[1]	Net Dependable Capacity (MW)[1]
Natural Gas	4[2]	29[2]	3,373	3,202
Large Hydro	1	7	1,265	1,265
Renewables	66	163[3]	417	277[4]
Storage	1	1	20	20
Subtotal	**72**	**200**	**5,075**	**4,764**
Less: Payable to the California Department of Water Resources	–	–	(120)[5]	(40)[5]
Total	**72**	**200**	**4,955**	**4,724**

Source: Department of Water and Power of the City of Los Angeles.

(1) Based on 2022 capacity ratings.

(2) Consists of the four Los Angeles Basin Stations (Haynes, Valley, Harbor and Scattergood) discussed and defined below. See "– *Once-Through-Cooling Units Phase-Out"* below for information regarding the future expected phase out of certain natural gas units.

(3) Includes 22 of the hydro units at the Los Angeles Aqueduct, Owens Valley and Owens Gorge hydro units that are certified as renewable resources by the CEC. Also included are Department-built photovoltaic solar installations, the Pine Tree Wind Project and a local small hydro plant. Not included are the units that were upgraded at the Castaic Plant.

(4) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

(5) Energy payable to the California Department of Water Resources for energy generated at the Castaic Plant. This amount varies weekly up to a maximum of 120 MW.

Los Angeles Basin Stations. The Department is the sole owner and operator of four electric generating stations in the Los Angeles Basin (the "Los Angeles Basin Stations"), with a combined net maximum generating capacity of 3,373 MW and a combined net dependable generating capacity of 3,211 MW. Natural gas is used as fuel for the Los Angeles Basin Stations. Ultra-low-sulfur distillate is used for emergency back-up fuel. See "– Fuel Supply for Department-Owned Generating Units and Apex Power Project." See also "– Projected Capital Improvements." The four Los Angeles Basin Stations are briefly described below.

Haynes Generating Station. The largest of the Los Angeles Basin Stations is the Haynes Generating Station, located in the City of Long Beach, California. The Haynes Generating Station currently consists of eleven generating units with a combined net maximum capacity of 1,614 MW and a net dependable capacity of 1,512 MW. Originally comprising six units, two of the original units were repowered in 2005 and replaced with a combined-cycle generating unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two–plus–one configuration (and are counted by the Department as three generating units). In 2013, the Department completed the replacement of an additional two of the original units with six advanced simple-cycle gas turbine units. In 2022, the Department completed the demolition of the four Haynes Generating Station Units that were decommissioned to create a construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Valley Generating Station. The Valley Generating Station is located in the San Fernando Valley and is currently comprised of a simple-cycle generating turbine unit and a combined-cycle generating unit, which consists of two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). The net maximum plant capacity for the Valley Generating Station is 555 MW. The total net dependable capacity for the Valley Generating Station is 532 MW. The Department expects to demolish four Valley Generating Station Units that were decommissioned in 2002 to create a construction area for a future energy project. The demolition of the decommissioned Valley Generating Station Units is not expected to impact the energy output of the Valley Generating Station. Demolition is expected to be completed by November 2026.

Valley Generating Station Gas Vent-Off. While conducting methane surveys across the State for the CEC in August 2020, the Jet Propulsion Laboratory observed an increase of methane vent-off over the Valley Generating Station reciprocating natural gas compressor area. The Department installed new design rod packing seals in December 2020 that have been working as designed.

Five Los Angeles Superior Court cases were filed related to the referenced vent-off at the Valley Generating Station. The most significant of the cases, a class action lawsuit with a putative class of 30,000 individuals, was dismissed in December 2021. Additionally, punitive damages were removed, and the number of causes of action was reduced. Those court actions significantly eliminate the financial recovery expected by plaintiffs' counsel. With the dismissal of the class action lawsuit, there are four remaining cases, including *Pueblo y Salud, Inc, et. al. v. Los Angeles Department of Water and Power, et al.*, 21STCV04346, the lead case. The remaining cases have an aggregate of approximately 2,500 individual plaintiffs represented by various counsel. All pending cases have been deemed related by the court and are assigned to the same judge in the Los Angeles Superior Court.

The Department's exposure for the Valley Generation Station, if there is liability, is not now known. The Department has notified insurance carriers which may afford possible coverage for the underlying incident(s), however, at the present time no insurance coverage nor the amount of coverage, if any, has been confirmed.

Harbor Generating Station. The Harbor Generating Station is located in Wilmington, California. The Harbor Generating Station is comprised of eight generating units, including five simple-cycle generating turbine units and a combined-cycle unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). Harbor Generating Station's net maximum capacity is 426 MW with a net dependable capacity of 425 MW. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process– State Water Resources Control Board*" and "*– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Scattergood Generating Station. The Scattergood Generating Station is located in Playa Del Rey, California and is currently comprised of two conventional steam boiler generating units, one combined-cycle unit, which consists of two generating units in a one-plus-one configuration, and two advanced simple-cycle gas turbines, for a total of six generating units, with a net maximum capacity of 778 MW and a net dependable capacity of 742 MW from natural gas. An original unit of the Scattergood Generating Station was decommissioned in 2015 and has been demolished to create the construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures.

Once-Through-Cooling Units Phase-Out. Generating units at the Los Angeles Basin Stations that currently utilize once-through-cooling have a total generation nameplate of 1,661 MW, and a net maximum capacity of 1,486 MW. In February 2019, then Mayor Eric Garcetti announced that these units would be phased out and replaced with energy storage and clean energy alternative assets. The Department has initiated the City's planning efforts for replacing the capacity of the once-through cooling units as they retire by December 31, 2029. As part of these planning efforts, the Department issued a distributed energy resources request for proposals ("DER RFP") in September 2020 to explore the potential of in-basin distributed energy resources. Meanwhile the CEC launched its Demand Side Grid Support ("DSGS") Program in Summer 2022, which closely resembles the Department's DER RFP. As the result, in late 2022 the Department started pursuing the CEC sponsored DSGS Program, which is funded by tax payers instead. The Department expects to launch the DSGS Program in 2024. In addition, the Department presented a 2022 Power Strategic Long-Term Resource Plan (the "2022 Strategic Long-Term Resource Plan") to the Board in September 2022, which details high level initiatives to address once-through cooling units' phase-out and align with LA100 Study scenarios, and to formalize a roadmap for achieving 100% carbon free energy by 2035. The 2022 Strategic Long-Term Resource Plan was finalized and released in July 2023. See also "–Renewable Power Initiatives – L.A.'s Green New Deal."

Other Department-Owned Generating Facilities. In addition to the Los Angeles Basin Stations, the Department is the sole owner of a number of other generating facilities. Certain of the Department's hydroelectric projects are described below. See also "–Renewable Power Initiatives."

Castaic Pump Storage Power Plant. The Castaic Pump Storage Power Plant is located near Castaic, California (the "Castaic Plant") just before the terminus of the west branch of the California Aqueduct at Castaic Lake. The Castaic Plant is the Department's largest source of hydroelectric capacity and consists of seven units. The Castaic Plant's net maximum capacity and net dependable capacity for the seven units is 1,265 MW. The seven units completed a modernization process in August 2016. A FERC license pursuant to which the Department operates the Castaic Plant expired in 2022. The Department, in partnership with the California Department of Water Resources (the "CDWR"), is in the process of renewing this FERC license. FERC has not yet issued a new license. Under federal regulations, FERC issued an annual license on February 3, 2022, for the continued operations of Castaic Power Plant under the current license conditions. This annual license will be automatically renewed until FERC issues a new license. The Castaic Plant provides peaking and reserve capacity and is normally not a source of energy to the Department's net base load requirements. The Castaic Plant obtains water supply via the water conveyance system (the "State Water Project") operated by the CDWR, which has frequently been the subject of litigation that generally alleges that the CDWR is illegally "taking" listed species of fish through operation of the State Water Project export facilities and that the CDWR should cease operation of the State Water Project pumps. The CDWR has altered the operations of the State Water Project to accommodate certain listed species, which has had the effect of reduced pumping from the affected waters. Future litigation of this nature could influence how the State Water Project is operated and further reduce water flow to the Castaic Plant. The Department cannot predict at this time what effect this type of litigation will have on the Power System. See "– Water Supply for Department-Owned Generating Units" below.

Owens Gorge and Owens Valley Hydroelectric Generation. The three Owens Gorge and seven Owens Valley hydroelectric generating units (the "Owens Gorge and Owens Valley Hydroelectric Generation") are located along the Owens Valley in the Eastern High Sierra region of the State. The aggregate net dependable capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 52 MW and the net maximum capacity totals 122 MW.

The Owens Gorge and Owens Valley Hydroelectric Generation is a network of hydroelectric plants which use water resources of the Los Angeles Aqueduct and three creeks along the Eastern Sierras. The water flow fluctuates from year to year and as a result water flow may be reduced from seasonal norms from time to time. Since 1995, the total aqueduct exports from Owens Valley to the City have gone from approximately 476,000 acre-feet per year to currently approximately 252,000 acre-feet per year (based on the 30-year median). This difference is due to environmental uses in the Owens Valley, including Mono Lake level restoration, Lower Owens River restoration, reduced groundwater pumping and Owens Lake dust mitigation. Consequently, this water use reallocation has resulted in a reduction of downstream hydroelectric generation, which is accounted for in the annual updates of the Power System's resource plan; however, efforts are underway to reduce the amount of water required for Owens Lake dust mitigation. An estimated reduction of up to 10,000 acre-feet may be achieved depending upon terms agreed upon with applicable regulatory authorities, and may result in increased aqueduct exports from Owens Valley to the City.

San Francisquito Canyon and the Los Angeles and Franklin Reservoirs. The Department also owns and operates twelve hydroelectric units located north of the City along the Los Angeles Aqueduct in San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs. The net aggregate dependable plant capacity of these smaller units is 42 MW and the net maximum capacity totals 78 MW.

Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units

The Department has additional generating resources available as capacity rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Also, the Department benefits from distributed generation ("DG") capacity connected to the Department's grid from customer solar photovoltaic installations through net metering and customer generation rates and from other DG units through a Feed-in-Tariff. These interests, as of December 31, 2023, are summarized in the following chart and discussed below. Each project participant with respect to jointly-owned units is generally responsible for providing its share of construction, capital, operating, decommissioning, and maintenance costs.

JOINTLY-OWNED GENERATING UNITS AND CONTRACTED CAPACITY RIGHTS IN GENERATING UNITS

Type	Number of Facilities	Department's Net Maximum Connected Capacity (MW)	Department's Net Dependable Connected Capacity (MW)
Coal	1	1,202(1)	1,202
Natural Gas	1	578	483
Large Hydro	1	496(2)	268(2)
Nuclear	1	387(3)	380
Renewables/Distributed Generation	81,110(4)	3,112	958(5)
Total	**81,114**	**5,775**	**3,291**

Source: Department of Water and Power of the City of Los Angeles.

(1) The Department's IPP entitlement is 48.62% of the maximum net plant capacity of 1,800 MW. An additional 18.17% portion of the IPP entitlement is subject to variable recall as set forth under "*Intermountain Power Project – Power Recalls*" below.

(2) The Department's Hoover Power Plant contract entitlement is 496 MW, which is 23.90% of the Hoover total contingent capacity and 14.7% of the firm energy. Hoover Power Plant output constantly varies due to low water levels at Lake Mead resulting from drought conditions.

(3) The Department's PVNGS entitlement is 9.66% of the maximum net plant capacity of 4,003 MW. See "*– Palo Verde Nuclear Generating Station*" below.

(4) The Department's contract renewable resources in-service include a hydro unit in the Los Angeles area, wind farms in Oregon, Washington, Utah and Wyoming, and customer solar photovoltaic installations and other DG units located in the Los Angeles region.

(5) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

Intermountain Power Project.

General. The IPP consists of: (i) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Delta, in Millard County, Utah; (ii) a +500 kilovolts ("kV"), direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System") (see "– Transmission and Distribution Facilities – *Southern Transmission System*"); (iii) two 50-mile, 345 kV, alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144-mile, 230 kV, alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"); (iv) a microwave communications system; (v) a railcar service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station"). Pursuant to a Construction Management and Operating Agreement between IPA and the Department, IPA appointed the Department as project manager and operating agent responsible for, among other things, administrating, operating and maintaining the IPP.

Power Contracts. Pursuant to a Power Sales Contract with IPA (the "IPP Contract"), the Department is entitled to 48.617% of the capacity of the IPP (currently equal to 875 MW). The term of the IPP Contract ends on June 15, 2027.

Pursuant to the IPP Contract, the Department is required to pay in proportion to its entitlement share the costs of producing and delivering electricity as a cost of purchased capacity. The Department also has available additional capacity in the IPP through an excess power sales agreement with certain other IPP participants (the "IPP Excess Power Sales Agreement"). Under the IPP Excess Power Sales Agreement the Department is entitled to an additional 18.168% of the capacity of IPP (currently equal to approximately 327 MW), subject to recall as described below. The IPP Contract requires the Department to pay for such capacity and energy on a "take-or-pay" basis as operating expenses of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

In Fiscal Year 2022-23, the IPP operated at a plant net capacity factor of 37.8% and provided approximately 5.9 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes approximately 3.9 million MWhs to the Power System.

Intermountain Generating Station upon the termination of the IPP Contract. In order to facilitate the continued participation of the Department and other power purchasers in the IPP beyond the IPP Contract's termination in 2027, the IPA Board issued the Second Amendatory Power Sales Contract which amended the IPP Contract to allow for the repowering of the plant to replace the coal units with combined cycle natural gas units by July 1, 2025 that would allow for compliance with greenhouse gas ("GHG") emissions performance standards. Pursuant to the provisions of the power sales contracts, the IPP participants also agreed to reduce the initially planned generation capacity of the repowered plant from 1,200 MW to 840 MW. IPA released a request for proposals in June 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with green hydrogen fuel (*i.e.*, hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% green hydrogen starting in 2025 and the subsequent goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. The request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was executed in early 2022 securing energy conversion and storage services. This contract will provide the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units in 2025. It is estimated that the repowering of the plant to the new combined cycle units at IPP will cost approximately $1.7 billion. This estimate does not include the hydrogen facilities being constructed. Upgrades to the Switchyard and replacement of converter stations are also being undertaken at an estimated cost of approximately $2.7 billion, reflecting a change in scope requested by the Department and the cities of Burbank and Glendale to upgrade portions of the converter station to 3,000 MW. SCPPA has issued bonds to finance a portion of the costs of the upgrades to the Switchyard and converter station replacements. See "– Transmission and Distribution Facilities – *Southern Transmission System.*" See also "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

The original power sales contracts, including the IPP Contract, will terminate on June 15, 2027, at which point the IPP Renewal Power Sales Contracts (which were executed in 2017) will immediately take operational effect and continue for a term ending in 2077. Most of the power purchasers under the original power sales contracts will continue to be IPP participants under the IPP Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the IPP Renewal Power Sales Contracts.

The city of Burbank will take a smaller share of generation capacity under the IPP Renewal Power Sales Contracts, and the Department and the city of Glendale both increased their respective generation shares. Under its IPP Renewal Power Sales Contract with IPA, the Department will be entitled to 71.442% of the capacity of the IPP. In connection with the execution of the IPP Renewal Power Sales Contracts in 2017, the Department also executed successor excess power sales agreements with certain other IPP participants which will continue to make available to the Department additional capacity in the IPP. The increase to the Department's share and additional available capacity in the IPP will become available to the Department when the IPP Renewal Power Sales Contracts take effect on June 16, 2027. Similar to its IPP Contract, the Department will be obligated to pay for the capacity and energy purchased under its IPP Renewal Power Sales Contract on a "take-or-pay" basis as operating expenses of the Power System.

The IPA has issued bonds to finance a portion of the costs of the IPP repowering project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Power Recalls. Under the existing IPP Excess Power Sales Agreements, certain IPP participants have a right to recall from the Department up to 18.168% of the capacity of IPP (currently equal to approximately 327 MW) for defined future summer or winter seasons or both, following no less than 90 days' notice and up to 43 MW of such capacity on a seasonal basis following no less than 90 days' notice. IPP Utah participants will recall 7.820% of the capacity of IPP (equal to 141 MW) from the Department for the summer season which started March 2024 and will end September 2024. The percentage of the capacity of IPP subject to recall will increase to 21.057% (equal to 177 MW) in 2027 upon the effectiveness of the Agreement for Sale of Renewal Excess Power which will take effect on the same day as the Renewal Power Sales Contract described above. The Department can give no assurance that the capacity of IPP subject to recall from the Department under the IPP Excess Power Sales Agreement or the Agreement for Sale of Renewal Excess Power will not be recalled in the future in accordance with the agreement terms.

Fuel Supply. IPA possesses coal supply agreements to fulfill the supply requirement of approximately 4.0 million tons per year. The coal is purchased under a portfolio of fixed price contracts that are of short and long-term in duration. However, as described below, supply chain issues resulting from the loss of coal production in the region and transportation challenges have dramatically reduced coal supply beginning in the later months of 2021 and are expected to impact coal supply for the remaining life of the coal plant. The largest coal producer in Utah experienced a fire in September 2022 and was planning to return to mining in 2024. However, it was announced in November, that the mine is closing indefinitely. The loss of the largest mine, combined with the logistics challenges in Utah, has dramatically reduced supply in the region including to IPA. As a whole, productions remains challenging for the remaining active mines in Utah.

The recent cost of coal delivered to the Intermountain Generating Station is substantially lower than current market prices for the region. However, IPA expects that the costs to fulfill IPP's coal demand will increase due to the scarcity of coal in the Western United States, if IPA is able to secure any additional coal as a replacement for the loss of sources under contract.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between IPA and the Union Pacific Railroad company, and the coal is transported, in part, in IPA-owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks. Both rail service and trucking services have suffered greatly due to a lack of human resources. Neither network is capable of supporting industrial demand; and IPA, like all coal-fired utilities in the United States, has seen large systemic failures in the transportation system.

Historically, IPP was able to maintain a minimum of 60 days of coal in inventory in the event of a coal supply disruption. However, due to the recent challenges in the coal supply chain, the number of days of coal in inventory has periodically declined below that level. As of the mid-December 2023, IPP maintained 39 days of coal in inventory. *{update to come}*

The Department has operational flexibility with respect to its use of IPP; however, the supply chain issues referenced above are likely to impact the operations of IPP and may constrain the Department's ability to utilize such resource.

For more information on the effect of certain environmental considerations on IPP, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Air Quality – Mercury*."

Apex Power Project. The Apex Power Project (the "Apex Power Project") is located in an unincorporated area of Clark County, north of Las Vegas, Nevada. The Apex Power Project includes the Apex Generating Station, which is a combined cycle generating station consisting of one 238 MW, nameplate rating, steam turbine generator, and two simple cycle, 203 MW, nameplate rating, combustion turbine generators. The Apex Power Project also includes heat recovery equipment, air inlet filtering, closed cycle cooling system, emission control system, exhaust stack, distributed control system, all necessary noise control equipment, and its associated real property. The Apex Generating Station has a net maximum capacity of 578 MW and a net dependable capacity of 483 MW. In March 2014, SCPPA acquired the Apex Power Project for the benefit of the Department, and the Department is entitled to 100% of the capacity and energy of the Apex Power Project under a take-or-pay power sales contract with SCPPA. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Hoover Power Plant.

General. The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility at Lake Mead, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Power Plant consists of 17 generating units and two service generating units with a total installed capacity of approximately 2,074 MW, and a minimum capacity of 650 MW. The Department has a power purchase agreement with the United States Department of Energy Western Area Power Administration ("Western") for 23.90% of total contingent capacity and 14.65% of the firm energy from the Hoover Power Plant through September 2067. The facility is owned and operated by the United States Bureau of Reclamation (the "Bureau of Reclamation").

Environmental Considerations. The lower Colorado River has been included in a critical Habitat Designated Area. This required the Bureau of Reclamation to prepare and file with the United States Fish and Wildlife Service (the "USFWS") a Biological Assessment on the effect of its operations of the lower Colorado River on endangered species therein (the "Biological Assessment"). After the Biological Assessment was filed, the USFWS issued a Biological and Conference Opinion regarding the Bureau of Reclamation's operations and outlined remedial actions to be taken to correct adverse effects to endangered species. Such remedial actions could affect the operation of the Hoover Power Plant, which would in turn affect the Hoover Power Plant customers, including the Department. The Department believes that any impact of the Biological and Conference Opinion on future operations will be minor; however, there is a possibility that future regulatory action will recommend major remediation actions that could have a material impact on the Hoover Power Plant customers' available capacity from the Hoover Power Plant. The Hoover Power Plant customers, including the Department, together with certain other parties, have implemented a plan in cooperation with the Bureau of Reclamation and the USFWS to mitigate negative effects on the Hoover Power Plant's energy production.

Palo Verde Nuclear Generating Station.

General. PVNGS is located approximately 50 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units (numbered 1, 2 and 3), with a net maximum capacity of 1,333 MW (unit 1), 1,336 MW (unit 2) and 1,334 MW (unit 3) and a dependable capacity of 1,311 MW (unit 1), 1,314 MW (unit 2) and 1,312 MW (unit 3). PVNGS's combined design capacity is 4,003 MW and its combined dependable capacity is 3,937 MW. Each PVNGS generating unit has been operating under 40-year Full-Power Operating Licenses granted by the Nuclear Regulatory Commission (the "NRC") expiring in 2025, 2026, and 2027, respectively. In

April 2011, the NRC approved PVNGS's license renewal application, allowing the three units to extend operation for an additional 20 years until 2045, 2046 and 2047, respectively.

Arizona Public Service Company ("APS") is the operating agent for PVNGS. On average, PVNGS has provided over 3.1 million MWhs of energy annually to the Power System. The Department has a 5.7% direct ownership interest in the PVNGS (approximately 224 MW of dependable capacity). The Department also has a 67.0% generation entitlement interest in the 5.91% ownership share of PVNGS that belongs to SCPPA through its "take-or-pay" power contract with SCPPA (totaling approximately 156 MW of dependable capacity), so that the Department has a total interest of approximately 380 MW of dependable capacity from PVNGS. Co-owners of PVNGS include APS; the Salt River Project; Edison; El Paso Electric Company; Public Service Company of New Mexico; SCPPA and the Department.

Nuclear Regulatory Commission. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities.

The aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan prompted the U.S. nuclear industry to form a task force under the direction of PVNGS's Chief Nuclear Officer to take immediate actions in ensuring the reliability of all U.S. nuclear plants. PVNGS instituted improvements driven by the findings from such task force. Among these improvements, is a staging of "flex" equipment, which includes mobile pumps, generators, hoses, and fire trucks that enable PVNGS to shift cooling water through the plant and power critical equipment in the event of a disaster.

Decommissioning Costs. The owners of PVNGS have created external trusts in accordance with the PVNGS participation agreement and NRC requirements to fund the costs of decommissioning PVNGS. Based on the 2022 annual funding status report which is based on a 2019 study of decommissioning costs, which is the most recent estimate available, the Department estimates that its share of the amount required for decommissioning PVNGS relating to the Department's direct ownership interest in PVNGS was approximately 71% funded and that its share of decommissioning costs through SCPPA was 85% funded. The Department's direct share of costs is $195.2 million and SCPPA's share is $209.3 million, of which the Department's portion is $140.3 million or 67%. Under the current funding plan, the Department estimates that its share of the decommissioning costs relating to the Department's direct ownership interest in PVNGS will be fully funded by accumulated interest earnings by the extended license expiration date of 2047. Such estimates assume 7% per annum in future investment returns and a 5% per annum cost escalation factor. The Department has received and is receiving less than a 7% per annum investment return on the decommissioning funds and cost increases have been averaging less than 5% per annum. No assurance or guarantee can be given that investment earnings will fully fund the Department's remaining decommissioning obligations at current estimated costs or that the decommissioning costs will not exceed current estimates. For a discussion of the Department's nuclear decommissioning trust fund and other investments held on behalf of the Department, see "GENERAL – Investment Policy and Controls."

Nuclear Waste Storage and Disposal. Generally, federal and state efforts to provide adequate interim and long-term storage facilities for low-level and high-level nuclear waste have proven unsuccessful to date. Although federal and state efforts continue with respect to such storage and disposal facilities, the Department is not able to predict the schedule for the permanent disposal of radioactive wastes generated at PVNGS. Since the spent fuel pools ran out of storage capacity, an independent spent fuel storage installation was built to provide additional spent fuel storage at the site while awaiting permanent disposal at a federally developed facility. The installation uses dry cask storage and was designed to accept all spent fuel generated by PVNGS during its lifetime. As of December 31, 2023, 152 casks, each containing 24 spent fuel assemblies, and 24 new casks, each containing 37 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel at a time, have been stored. Storage costs are partially paid using funds received by APS pursuant to a settlement agreement with the United States government relating to nuclear waste disposal fees.

Mohave Generating Station – Operations Ceased. The Mohave Generating Station was a coal-fired electric generating station located near Laughlin, Nevada, that ceased operations in 2005. The Department owned a 30% interest in the Mohave Generating Station and still owns a 30% interest in the site. The other co-owners are Edison and NV Energy (formerly known as Nevada Power Company). The Mohave Generating Station generating units were removed from service at the end of 2005. A major plant decommissioning was completed in 2012. As required by the Nevada Division of Environmental Protection, minor cleanup, ground water monitoring and upkeep of the plant site will continue for a number of years after the decommissioning to ensure that the integrity of the coal ash landfill is maintained and that the groundwater is protected from contamination. In accordance with an approved site disposition plan, the co-owners of the Mohave Generating Station have made approximately 80% of the property of the Mohave Generating Station available for public sale. Any sales transaction will require approval from the Board and City Council. The remaining property would be retained by the co-owners for ongoing monitoring, maintenance, and environmental compliance purposes. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Coal Combustion Residuals*."

Navajo Generating Station – Operations Ceased. The Navajo Generating Station was a coal-fired, electric generating station located near the City of Page, Arizona, that ceased operations in 2019. The Salt River Project Agricultural Improvement and Power District, a political subdivision of the state of Arizona, and the Salt River Valley Water Users' Association, a corporation (together, the "Salt River Project") is the operating agent of the Navajo Generating Station. The Department sold its interest in the Navajo Generating Station in 2016, however the Department is still responsible for its portion of decommissioning costs.

LA100 Study

In accordance with three City Council motions passed in 2016 and 2017, the Department partnered with the NREL to perform the "LA100: The Los Angeles 100% Renewable Energy Study" (the "LA100 Study"). This unprecedented, three-year study identified several pathways that would allow the City to achieve a 100%-renewable-energy portfolio no later than 2045. The NREL identified four overall scenarios with various modeling assumptions for the Department to achieve its sustainability goals, including one scenario to achieve its goals by 2035. The NREL also analyzed how the scenarios could affect the region's air quality, GHG emissions, public health, jobs, and economic activity. At the direction of the City Council, the study incorporated the CalEnviroScreen, allowing the NREL to identify pathways that will be not only economical for the utility but also equitable for communities.

The LA100 Study has yielded a tremendous amount of data and new, state-of-the-art models that provide the Department with a variety of perspectives on approaches toward 100% renewable energy. The results of the LA100 Study will continue to inform the Department's internal planning processes, including its Strategic Long-Term Resource Plan and other public outreach efforts that are designed to ensure a just and equitable transition for the City. The Financial Services Organization of the Department has conducted a preliminary rate analysis to determine the rate impacts for each of the scenarios in the LA100 Study. However, more in-depth analysis on the specific path is needed to ascertain more accurate rate analysis. The total cumulative cost through 2045 of new investment needed to achieve the suite of modeled scenarios ranges from approximately $57 billion to $87 billion, depending on the scenario, load projection, and the target year.

At the conclusion of the LA100 Study, it was determined that the LA100 Study provided various ways to reach 100% clean energy but it did not fully address the topic of equity as part of the transition. As a result, the LA100 Equity Strategies Study was commissioned by the Board. The independent study was conducted by the NREL and by UCLA with focused research in five priority areas: (1) affordability and energy burdens; (2) access to and use of energy technologies, programs, and infrastructure; (3) health, safety, and community resilience; (4) jobs and workforce development; and (5) inclusive community involvement. The ultimate goal of the LA100 Equity Strategies Study is for all communities across the City to share in the benefits and the burdens of the clean energy transition and to identify what policies should be put in place to achieve such outcomes. The LA100 Equity Strategies study report was released in November 2023. The report details a number of findings, recommendations and strategies addressing inequities in the clean-energy transition and is designed to assist the

Department to make data-driven, community-informed decisions for equitable investment and program development towards achieving a 100% carbon-free energy portfolio.

Renewable Power Initiatives

The Department expects to continue to procure a renewable power resource portfolio that satisfies applicable State requirements, the main provisions of which are currently contained in the California Renewable Energy Resources Act ("SBX 1-2"), the California Global Warming Solutions Act of 2006 ("AB 32" or the "Global Warming Solutions Act"), the Clean Energy and Pollution Reduction Act of 2015 ("SB 350"), and the 100 Percent Clean Energy Act of 2018 ("SB 100"). For a discussion of certain State legislation and regulations affecting the Department, including AB 32, SB 350, SB 1368, SBX 1-2, SB 100, and the Clean Energy, Jobs, and Affordability Act of 2022 ("SB 1020"), see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments." Certain components of the Department's renewable power resource portfolio are described below. Available capacity with respect to such renewable power resources will vary as they are intermittent resources. Wind power, both obtained through power purchase agreements and resources owned by the Department, provided 11% and 13% of the Department's energy in 2021 and 2022, respectively, or about one-third of the renewable energy, which comprised 35% and 36% of the total energy mix in 2021 and 2022, respectively, as reflected in the Department's Annual Power Content Label for such years.

Large Scale Wind Energy. Through power purchase agreements, the Department has secured large scale wind farm output in a number of areas to provide a diversity of wind power resources. Such wind energy for the Department is being generated in wind farms located in the States of California, Oregon, Washington, Utah, and Wyoming, and New Mexico. Such power purchase agreements provide for an aggregate of 1,143 MW of wind energy. In addition to these power purchase agreements, wind farms with output of approximately 880 MW are also subject to Department options to purchase such assets.

Certain of these projects are described as follows:

Milford Wind Corridor Phase I Project. The Milford Wind Corridor Phase I Project (the "Milford I Project") began commercial operation in November 2009 and consists of SCPPA's purchase of all energy generated by a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah (the "Milford I Facility"), for a term expiring in November 2029 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase I, LLC. Energy from the Milford I Facility is delivered to SCPPA over an approximately 90-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 6,764,301 MWhs of energy from the Milford I Facility over the delivery term. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 92.5% share of the Milford I Project on a "take-or-pay" basis as an operating expense of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Milford Wind Corridor Phase II Project. The Milford Wind Corridor Phase II Project (the "Milford II Project") began commercial operation in May 2011 and consists of SCPPA's purchase of all energy generated by a 102 MW nameplate capacity wind farm comprised of 68 wind turbines located near Milford, Utah (the "Milford II Facility"), for a term expiring on June 30, 2031 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase II, LLC. Energy from the Milford II Facility is delivered to SCPPA over an approximately 88-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 4,467,600 MWhs of energy from the Milford II Facility over the delivery term. In connection with the issuance of bonds relating to the Milford II Project, the Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 95.098% share of the Milford II Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 4.902% output entitlement share of Milford II Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Linden Wind Energy Project. The Linden Wind Energy Project (the "Linden Project") began commercial operation in June 2010 and consists of SCPPA's acquisition of a 50 MW nameplate capacity wind farm comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington. The Linden Project was developed and constructed by Northwest Wind Partners, LLC ("Northwest Wind"). SCPPA acquired the project from Northwest Wind pursuant to the terms of an asset purchase agreement between SCPPA and Northwest Wind. Energy from the Linden Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Linden Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the acquisition of the Linden Project. The Department has entered into a power sales agreement with SCPPA for a term expiring in 2035 (unless earlier terminated) that provides for the Department to pay its 90.00% share of the Linden Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 10.00% output entitlement share of the Linden Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the "Windy Point Project"). The Windy Point Project is owned and operated by Windy Flats Partners, LLC ("Windy Flats"). Pursuant to a power purchase agreement with Windy Flats, SCPPA has agreed to purchase from Windy Flats all energy from the Windy Point Project for a delivery term that was originally expiring in 2030 (unless earlier terminated). In March 2023, an amendment to the original power purchase agreement was approved which extended the delivery term for an additional four years, to 2034. Energy from the Windy Point Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs of energy from the Windy Point Project. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay its 92.37% share of the Windy Point Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 7.63% output entitlement share of Windy Point Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Pine Tree Wind Project. The Pine Tree Wind Project (the "Pine Tree Wind Project") is a wind generating facility north of Mojave, California, consisting of 90 wind turbines owned and operated by the Department. The Pine Tree Wind Project began commercial operation in June 2010 and has a nameplate capacity of 135 MW. As part of normal operating procedures, the Department staff has notified federal and State authorities concerning mortalities of golden eagles. Since June 2009, the Department staff has found nine golden eagle carcasses in the proximity of the Pine Tree Wind Project. The Department has completed advanced monitoring studies and surveys to research golden eagle behavior within the vicinity of the Pine Tree Wind Project and to determine potential causes of the eagle mortalities and mitigation options relating to the golden eagles. The Department previously conducted tests using radar and automated deterrent technology in detecting and deterring golden eagles and other birds of prey at the Pine Tree Wind Project. Golden eagles are a protected species, and the death or injury to a golden eagle in some circumstances can result in fines and penalties, including criminal sanctions. As of June 2017, the Department entered into a settlement agreement with the USFWS to address the golden eagle mortalities at the Pine Tree Wind Project. The Department completed its golden eagle research and development study as required by the settlement agreement and submitted the final summary report to USFWS in September 2020. On December 29, 2020, the Department received a letter from the USFWS indicating that the Department had fulfilled the terms of the settlement agreement with respect to the research and development study, payment, and meet and confer with USFWS staff. The Department is still coordinating with the USFWS to obtain an incidental take permit for golden eagles as a separate requirement under the settlement agreement. In order to protect condors, a protected species under State and federal law, the Department has implemented a condor detection protocol that includes turbine curtailment when condors are observed in the immediate area. Additionally, the Department has prepared a condor conservation plan and obtained an incidental take permit for California condors on November 28, 2023. The condor conservation plan outlines the avoidance measures that are currently being implemented and the proposed compensatory mitigation measures in an effort to protect and address the declining condor population.

Red Cloud Wind Project. In November 2020, the Department entered into a power sales agreement with SCPPA to purchase renewable energy purchased by SCPPA from the Red Cloud Wind Project located in New Mexico (the "Red Cloud Wind Project"). Pursuant to a power purchase agreement with Red Cloud Wind, LLC, SCPPA purchases 331 MW of renewable energy to be delivered to the Department at the Navajo 500 kV Switching Station for a 20-year term. The Red Cloud Wind Project was developed by Pattern Energy and commenced commercial operation on December 22, 2021. The Red Cloud Wind Project is expected to deliver an annual average of approximately 1,333,000 MWhs of renewable energy to the Department.

Distributed Energy Resource Programs. The Department has implemented the following programs to encourage the development of solar energy in Los Angeles: (i) the Solar Incentive Program in which residential and commercial customers are encouraged to install eligible solar photovoltaic systems with incentive funding provided by the Department, which ended in December 2018; (ii) Department-built solar projects on City-owned properties; (iii) the Solar Rooftops Program, which places Department-owned solar panels on qualifying residential rooftops in exchange for predefined lease payments to the customer; (iv) a Feed-in-Tariff ("FiT") program, launched on February 1, 2013, which has a total installed capacity of 101.7 MW comprised of 4 MW of solar photovoltaic generation in the Owens Valley and 4 MW of renewable landfill gas generation, and 93.7 MW of photovoltaic generation installed within the Department's service territory and connected to the Department's electric distribution system; (v) the Shared Solar Program ("SSP"), which enables residential customers living in multi-family dwellings to fix a portion of their electric bills through Department solar installations; (vi) the Virtual Net Energy Metering ("VNEM") pilot program, which launched in March 2021 and allows developers or building owners to install solar arrays on multi-family dwelling unit buildings and split the energy sales proceeds with tenants; and (vii) the FiT Plus program, which facilitates the installation of battery storage with existing and new FiT projects.

Under the California Solar Initiative ("SB-1"), POUs are required to establish programs supporting the stated goal of the legislation to install 3,000 MW of photovoltaic capacity in the State, and to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer funded incentives. The Solar Incentive Program used $339 million of ratepayer funds mandated by SB-1 to administer the program and subsidize customers for customer-owned solar projects to offset their electricity use. As of December 2018, the Department committed all funds available for this program for 279.7 MW of installations.

The Department currently has 25.9 MW of Department–built solar projects on City-owned properties. The Adelanto Solar Power Project is a 10 MW solar photovoltaic system placed into commercial operation in June 2012, which is expected to deliver 450,000 MWhs of energy over 25 years, located at the existing Adelanto Switching and Converter Station near Adelanto, California. In addition, the Pine Tree Solar Project was placed into commercial operation in March 2013. The Pine Tree Solar Project is an 8.5 MW solar photovoltaic system expected to deliver 350,000 MWhs of energy over 25 years, located at the Department's existing Pine Tree Wind Project in the Tehachapi Mountains, California. The remaining 6.9 MW includes installations spread across various City owned properties in the Los Angeles Basin as well as a 500kW system in the Owens Valley.

The Department has entered into the following 13 power purchase agreements ("PPAs") for the purchase of renewable energy from 1,495 MW of solar photovoltaic projects:

- One PPA with an option to purchase is a 25-year contract with K Road Moapa Solar, LLC, which changed its name to Moapa Southern Paiute Solar, LLC, for 250 MW, delivering up to 618,000 MWhs a year to the Department. The solar facility is located on Moapa Band of Paiute Indians tribal land north of Las Vegas, Nevada. The Department acquired the approximately 5.5-mile transmission line associated with the facility, which achieved full commercial operation in December 2016.

- The second PPA with an option to purchase is a 20-year contract through SCPPA for 210 MW of the Copper Mountain Solar 3 Project developed by an affiliate of Sempra U.S. Gas and Power. Copper Mountain Solar 3 Project is near Boulder City, Nevada and is expected to deliver 515,000 MWhs of renewable energy a year to the Department and began full commercial operation in April 2015.

- The third PPA with an option to purchase is a 20-year contract for 60 MW of the RE Cinco Solar Project developed by Recurrent Energy, an affiliate of Canadian Solar Inc. RE Cinco Solar Project is near the Mojave Desert in Kern County and is expected to deliver an annual average of 182,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in August 2016.

- The fourth PPA with an option to purchase is a 25-year contract through SCPPA for 105 MW of the Springbok I Solar Farm Project developed by Avantus (formerly 8Minutenergy). Springbok I Solar Farm Project is near the Mojave Desert in Kern County and is expected to deliver an average of 284,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2016.

- The fifth PPA with an option to purchase is a 27-year contract through SCPPA for 155 MW of the Springbok II Solar Farm Project, which is adjacent to the Springbok I Solar Farm Project and was developed by Avantus. Springbok II Solar Farm Project is expected to deliver an average of 420,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in September 2016.

- The sixth PPA with an option to purchase is a 27-year contract through SCPPA for 90 MW of the Springbok III Solar Farm Project, which is adjacent to the Springbok I and Springbok II Solar Farm Projects and was developed by Avantus. Springbok III Solar Farm Project is expected to deliver an average of 240,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2019.

- The seventh PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 1, is a 25-year contract through SCPPA for 175 MW of energy and 131.25 MW/525 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 1 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 2, and is being developed by Avantus, with commercial operation expected in the third quarter of calendar year 2024. Eland Solar & Storage Center, Phase 1 is expected to deliver an average of approximately 702,000 MWhs of renewable energy a year to the Department.

- The eighth PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 2, is a 25-year contract through SCPPA for 200 MW of energy and 150 MW/600 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 2 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 1, and is being developed by Avantus, with commercial operation expected in the first quarter of calendar year 2025. Eland Solar & Storage Center, Phase 2 is expected to deliver an average of approximately 803,000 MWhs of renewable energy a year to the Department.

- The ninth through thirteenth PPAs are related to the Beacon Solar Project Sites 1 thru 5. The Beacon Property, located in the Mojave Desert near the Pine Tree Wind Project, is a 2,500-acre property purchased by the Department from Nextera Energy Resources in 2012. Five PPAs and associated agreements have been executed for the development of five solar sites totaling 250 MW within the Beacon Property. Each of the five solar sites achieved commercial operation at different dates within the years 2016 and 2017, and are expected to generate an average of 581,000 MWhs per year of solar energy in aggregate over a term of 25 years. The PPAs provide the Department with an option to purchase the solar projects after the developers have realized the federal tax benefits.

In connection with the implementation of these PPAs, the Department has upgraded certain transmission assets to accommodate these projects in the Barren Ridge area. See "– Transmission and Distribution Facilities – *Barren Ridge Renewable Transmission Project*."

The Department's 450 MW FiT program allows the Department to purchase, through power purchase contracts, electricity generated from program participants' renewable energy generating sources. Such sources are to be located within the Department's service territory and connected to the Power System. The energy purchased through the FiT program is expected to count toward the Department's RPS targets. As discussed above, as part of the PPAs for solar development on the Beacon Property, the Beacon Solar developers installed additional solar in the Department's service territory. The Department has allocated the capacity of the original 150 MW FiT program. The Department obtained approval from the City Council to expand the FiT program by an additional 300 MW of capacity. The first 50 MW offering of this expansion was authorized in January 2020. In addition to increasing the FiT program from 150 MW to 450 MW over a number of years, the FiT program will now accommodate all renewable technologies approved by the CEC and expand each project's maximum capacity, previously set at 3 MW, to 10 MW. The FiT Plus and VNEM pilot programs will use 10 MW and 5 MW of the existing FiT capacity, respectively. The FiT Plus pilot program encourages the installation of battery energy storage with local solar projects, making solar energy dispatchable, while increasing the power grid's reliability and resiliency. The VNEM pilot program facilitates the installation of solar projects on multifamily dwellings, and allows renters to readily access the benefit of these systems. In April 2023, the Board approved the use of an additional 75 MW of capacity for the FiT programs and the Department introduced a FiT Carport and Canopy Incentive program. Out of the 450 MW authorized by City Council, the use of a total of 275 MW has been approved across all FiT programs.

Geothermal Development. The Department executed a power sales agreement with SCPPA for 84.62% of the energy output, or 114 GWhs annually, of the Don A. Campbell Phase I Geothermal Energy Project (the "Don Campbell Phase I Project"), which began commercial operation on January 1, 2014. The Don Campbell Phase I Project consists of SCPPA's purchase of all energy generated by a 16.2 MW nameplate capacity binary geothermal power plant comprised of eight drilled commercial wells located in Mineral County, Nevada for an initial delivery term of 20 years expiring December 31, 2033.

In addition, in April 2015, the Department executed a power sales agreement with SCPPA for 100% of the energy output, or 135 GWhs annually, of the Don A. Campbell Phase II Geothermal Energy Project (the "Don Campbell Phase II Project" and, together with the Don Campbell Phase I Project, the "Don Campbell Projects"), which expires in September 2035 and is located in the same vicinity as the Don Campbell Phase I Project. The Don Campbell Phase II Project is an expansion of the Don Campbell Phase I Project by the same developer, Ormat Nevada, Inc., and began commercial operation in September 2015. The nameplate capacity for the Don Campbell Phase II Project is 16.2 MW.

In addition to the Don Campbell Projects, the Department executed a power sales agreement with SCPPA in September 2013 for a share of the output purchased by SCPPA from the Heber-1 Geothermal Project (the "Heber-1 Project"). The energy delivery commencement date was February 2, 2016 for an initial term of ten years. The Heber-1 Project is an existing geothermal complex which includes the Heber-1 double flash steam unit and the Gould 1 bottoming binary unit, located in Imperial County, California. The net energy generated from the Heber-1 Project is expected to be 46 MW. The Department's share was 66.67% (30.68 MW) in the first three years and is 78.0% (35.88 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 285 GWhs annually.

In addition, the Department executed a power sales agreement with SCPPA in December 2016 for a share of the output purchased by SCPPA from the Ormesa Geothermal Complex Project (the "Ormesa Project"). The energy delivery commencement date was January 1, 2018 for a term of 25 years, ending on December 31, 2042. Similar to the Heber-1 Project, the Ormesa Project is an existing geothermal complex which includes two active binary units and one active bottoming unit, located in Imperial County, California. The generation capacity of the project is 35 MW. The Department's share is 85.71% (30 MW) of the energy output. The equivalent average energy delivered to the Department is expected to be 250 GWhs annually.

In May 2017, the City Council approved a power sales agreement with SCPPA for 100% of the output purchased by SCPPA from the Ormat Northern Nevada Geothermal Portfolio Project. At full service, this project provides the Department with approximately 163.54 MW of renewable geothermal energy from six power plants in various locations in Nevada. This amount is expected to represent approximately 5% of the Department's renewable energy portfolio in 2030. Energy delivery from the project stepped up in three phases from December 31, 2017 to December 31, 2022 as follows: 60 MW minimum and 85 MW maximum by December 31, 2018 (which was achieved), cumulative 90 MW minimum and 130 MW maximum by December 31, 2020 (which was achieved), and cumulative 135 MW minimum and 185 MW maximum by December 31, 2022 (which was achieved). After December 2022, the maximum annual energy received by the Power System from the project is expected to be 1,620 GWhs. The power sales agreement with SCPPA expires in December 2043.

Biomass Development. In March 2018, the City Council approved a power purchase agreement with SCPPA for a share of the output of the ARP-Loyalton Biomass Project in Sierra County, California, which began commercial operation in April 2018. SCPPA partnered with other State POUs to purchase a total of 18 MW of capacity for a term of five years towards satisfaction of procurement obligations under SB 859. The Department's share of the ARP-Loyalton Biomass Project was 8.9 MW. Following the bankruptcy of the operator and its parent company, energy deliveries from the ARP-Loyalton Biomass Project ceased in February 2020 and did not resume. The power purchase agreement for the output of the project expired by its terms on April 19, 2023. The Department has also contracted with SCPPA to purchase 5.4 MW of rated capacity from the Roseburg SB 859 biomass project. These two power purchase arrangements allow the Department to meet its requirement to purchase 14.3 MW of rated capacity from biomass sourced energy facilities in order to comply with SB 859. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Biomass Legislation*."

Energy Storage Development. In connection with the implementation of State law, the Department is developing viable and cost-effective energy storage systems. The goals of the energy storage systems include reducing emissions of GHGs, reducing demand for peak dispatchable generation and improving the reliability of the electric grid. Although energy storage systems themselves are not considered renewable resources, they facilitate the integration of renewable resources into the Power System. To date, the Department has implemented several small energy storage systems throughout the Power System, including:

- The 12 kW Fire Station 28 Battery Energy Storage System (BESS), located near the Porter Ranch area, commenced operation in October 2017.
- The 60 kW Lithium-Ion BESS, located at the Department's La Kretz Innovation Center, was integrated into the existing solar panel system in 2016.
- The 55 kW Lithium-Ion BESS, located at the Department's Truesdale Training Center, was commissioned in 2017.
- The 20 MW Beacon utility-scale BESS project, located on the Beacon Property, which commenced operation in October 2018.
- The 1.5 MW Lithium-Ion BESS, located at the Springbok 3 solar plant, installed in October 2019 for technical and operational performance demonstrations.
- The 100 kW Lithium-Ion BESS and 100 kW Flow BESS, located at the Department's headquarters (John Ferraro Building), which commenced operation in November 2019.

In addition, as discussed above, in 2020, the Department entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. Phase 1 is expected to be commissioned in 2024 and Phase 2 is expected to be commissioned in 2025.

See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Energy Storage Legislation*."

The Department issued a Standalone Energy Storage RFP, through SCPPA, for various technologies, including Long Duration Energy Storage (LDES). Following review of the proposals received, the Department will begin negotiations with the vendor(s) that meets the Department's requirements.

Green Power Program. The Department offers its Green Power Program to all customers at a premium over standard rates. "Green Power" is produced from renewable resources such as solar and wind energy, rather than fossil-fueled or nuclear generating plants. This voluntary program includes customer-selected levels of Green Power purchases, subject to specified minimum requirements. Approximately 9,124 Department customers subscribed to the Green Power Program as of December 2023. The Department is working on Green Power Program improvements that are intended to increase both the number of participants and the amount of green energy purchased through the program.

Other Renewable Energy Project Developments. The Department, on its own and through SCPPA, has received proposals from renewable energy resources such as solar photovoltaic, wind, biomass, small hydro, solar thermal and geothermal power via solicitations. The Department is also considering opportunities related to utilization of land located in the Owens Valley area of the State for solar, wind or geothermal and for improved transmission access to geothermal energy. In addition, as part of then Mayor Eric Garcetti's announcement in February 2019 that certain natural gas units will be phased out and replaced with renewable energy producing assets, the Department will be exploring options over the next few years to develop such assets for the Power System. See "THE POWER SYSTEM – Department Owned Facilities – *Once-Through-Cooling Units Phase-Out*" for more information. Additional renewable energy resources will be obtained; however, the Department's participation in or acquisition of any specific renewable energy project will be subject to City Council approval when required, and the costs and schedules for implementation and feasibility of any such alternative energy projects may vary materially from initial projections.

L.A.'s Green New Deal. On February 10, 2020, then Mayor Eric Garcetti released his Executive Directive No. 25 implementing L.A.'s Green New Deal. As part of this directive, the City expects the Department to provide equitable access to clean energy programs, build zero carbon microgrids in City owned infrastructure, deploy smart meters City-wide and institute other similar initiatives. The Department is studying how to implement this directive and other renewable power related directives and the effect they will have on the finances and operations of the Power System.

On April 19, 2021, then Mayor Eric Garcetti declared in his 2021 Los Angeles State of the City address his goal for the Department to provide an energy mix that is 80% renewable and 97% GHG-free resources by 2030, a full six years ahead of the L.A. Green New Deal, and to use the LA100 Study as a guide to fulfill President Biden's energy vision, with a goal of 100% carbon-free energy by 2035. To achieve these goals, the then Mayor referenced the Department's transition of Scattergood Generating Station to clean energy alternatives, the construction of the Red Cloud Wind Project in New Mexico, the partnership with the Navajo Nation for solar energy, and the supply of IPP with green hydrogen fuel. For more information on the LA100 Study, see "THE POWER SYSTEM – *LA100 Study*." For more information on the transition of Scattergood Generating Station, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board." For more information on the Red Cloud Wind Project, see "THE POWER SYSTEM – Renewable Power Initiatives – *Red Cloud Wind Project*." For more information on the Navajo Project, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units - *Navajo Generating Station – Operations Ceased*." For more information on the re-powering of IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project – Intermountain Generating Station upon the termination of the IPP Contract*."

The Clean Grid LA Plan Update was presented to the Board on May 11, 2021. The Clean Grid LA Plan Update is a 10-year roadmap that aligns with the LA100 Study to assist the Department with its clean energy goals. Elements of the Clean Grid LA Plan include providing 80% renewable and 97% GHG-free resources by 2030, accelerating transmission projects, transforming local generation, accelerating energy storage, and deploying distributed energy resources equitably. The Department plans to construct a combined cycle generating system capable of utilizing green hydrogen at Scattergood Generating Station which is expected to be in-service by 2029. Moreover, the Department continues to assess the potential opportunities for additional green hydrogen-fueled electricity generation across the coastal, in-basin generating stations. In addition to the Scattergood Green Hydrogen-Ready Modernization Project, the Department plans to convert Haynes Unit 8 from once-through cooling to wet cooling by 2027.

To fully understand the opportunities for developing a comprehensive green hydrogen economy in California, the Department is engaged with the Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES"). ARCHES is a public-private partnership led by the California Governor's Office of Business and Economic Development (GO-Biz) that is seeking to secure and maximize federal, state, and private funding for a California hydrogen hub. Most significantly, ARCHES is seeking federal funding through the federal Department of Energy's Regional Clean Hydrogen Hubs program which includes up to $7 billion to establish no more than 10 regional hydrogen hubs across the country. Through the ARCHES framework, the Department is collaborating with partners across the region and advocating for the development of local green hydrogen economy.

On May 19, 2022, the City Council voted to instruct the Department and the Port of Los Angeles ("POLA") to coordinate a local effort to create and submit a proposal to the Department of Energy proposing the Greater Los Angeles area for consideration as a regional green hydrogen hub. Through ARCHES, the Department and its partners submitted an application that details a proposed clean hydrogen ecosystem in California comprised of new and existing projects. On October 13, 2023, President Biden and Energy Secretary Jennifer Granholm announced $7 billion in awards for seven regional clean hydrogen hubs, of which the California-centered hub will receive $1.2 billion. The Department continues to work with both public and private entities to develop the necessary partnerships and governance structures, conduct market and system value benefit studies, and gather stakeholder feedback. The development and outcomes from this effort will be foundational to the Department's decarbonization efforts at the Los Angeles Basin Stations.

On September 1, 2021, the City Council voted to instruct the Department to "prepare a Strategic Long-Term Resource Plan that achieves 100% carbon-free energy by 2035, in way that is equitable and has minimal adverse impact on ratepayers." In addition, the City Council instructed the Department to "create a long term hiring and workforce plan . . . ensuring project labor agreements, [payment of] prevailing wage[s] . . . [with] hiring from environmentally and economically disadvantaged communities." The Department initiated its Strategic Long-Term Resource Plan in September 2021 with a stakeholder process and incorporating the Clean Grid LA Plan and key findings from the LA100 Study for Board consideration.

As previously noted, the Department released a final version of the 2022 Strategic Long-Term Resource Plan in July 2023. The 2022 Strategic Long-Term Resource Plan models three cases for achieving 100% carbon-free energy by 2035, as well as a reference case used for comparison purposes, that represents the minimum investments needed to comply with the requirements of SB 100 (see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments"). The 2022 Strategic Long-Term Resource Plan utilizes the same modeling methodology and approach as the LA100 Study. For each of the three cases modeled, the net present value of the estimated total cumulative bulk power portfolio cost across the study horizon of 2022 through 2045 is in excess of $80 billion. The 2022 Strategic Long-Term Resource Plan represents only a conceptual plan and encompasses numerous challenges related to availability of technology, implementation feasibility, system reliability and affordability. The 2022 Strategic Long-Term Resource Plan does not include potential cost savings from new sources of funding such as the federal Inflation Reduction Act, the federal Bipartisan Infrastructure Law, and state and federal grants. The next iteration of the Department's Strategic Long-Term Resource Plan, the 2024 Strategic Long-Term Resource Plan will be an update to the 2022 Strategic Long-Term Resource Plan, and will focus on understanding rate drivers and additional clean energy opportunities to refine and optimize costs over the long-term.

Energy Efficiency

General. The Charter authorizes the Department to engage in and finance activities related to the efficient use of energy and a number of State laws expressly require utilities such as the Department to collect and spend funds for these activities. The Department has a commitment to energy efficiency and continues to pursue cost-effective means of reducing or avoiding the need to generate electricity (particularly during peak periods). These activities defer the need to acquire costly new generating facilities, improve the value of electric service to customers and increase the Department's overall load factor, thereby reducing or avoiding negative environmental impacts from power generation. Moreover, State laws enacted in 2005 and 2006 require POUs, such as the Department, in procuring energy, to first implement all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible, and to provide annual reports to customers and to the CEC describing their investment in energy efficiency and demand reduction programs. AB 2021, which became a law in 2007, required IOUs and POUs to identify energy efficiency potential and establish annual efficiency targets to enable the State to meet the goal of reducing total forecasted electricity consumption by 10% by 2020. The Department adopted a goal in August 2014 of achieving up to 15% energy savings by the end of 2020, which was achieved. The Department is now focused on a goal of achieving additional energy savings of 3,431 GWhs from 2023 to 2035, surpassing the 2,628 GWhs of projected savings reflected in the LA100 Study.

Program and Portfolio Highlights. The Department's balanced portfolio of programs provides opportunities for all customers to benefit from cost effective energy efficiency. This approach targets large energy users and hard-to-reach customers who would not otherwise be able to invest in energy efficiency services, broadly addresses energy end uses in the built environment, focuses on reducing consumption during times of peak demand, and provides quality job opportunities for the local workforce. These programs include financial incentives for the installation of a variety of efficiency measures, free energy saving products, technical assistance incentives for business and industry, codes and standards, and education and awareness. The following list provides examples of programs that demonstrate the portfolio's ability to reach all customer types.

Comprehensive Affordable Multifamily Retrofits. The Comprehensive Affordable Multifamily Retrofits (the "CAMR") program provides low-income tenants and affordable housing property owners access to energy efficiency retrofits, building electrification measures, and on-site solar installation. The participating housing providers receive free energy assessments and assistance in scoping retrofit projects based on opportunities for energy savings, cost reductions, and GHG emissions reduction. Participating properties must meet affordability requirements of at least 66% of households at or below 80% of the area median income, consist of five or more units, and install energy improvements that equate to at least 10% in energy savings.

Efficient Product Marketplace. The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point of sale credit option to customers during their online purchases, eliminating the need for completing a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare and choose offers from a list of local third-party vendors.

Food Service Program. For in-store purchases, the Food Service Program offers an instant rebate as a line item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment. Beginning in 2024, the Food Service Program will start offering electrification incentives for all electric commercial cooking equipment & appliances.

Customer Performance Program. The Custom Performance Program (the "CPP") provides cash incentives for energy savings achieved through the implementation and installation of various energy efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP's Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP's Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers' individual efficiency projects' energy savings. The CPP has achieved over 608 GWhs of energy savings since 2007. In mid-2024 CPP will be rebranded as Business Offerings for Sustainable Solutions (BOSS). The new program will also offer electrification incentives for space/water heating end uses.

Commercial Lighting Incentive Program. The Commercial Lighting Incentive Program ("CLIP") offers customers incentives to install newly purchased and installed energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (kW). CLIP's calculated savings approach allows customers to tailor their lighting efficiency upgrades to meet their lighting needs better, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 803 GWhs of energy savings since 2000.

Commercial Direct Install Program. The Commercial Direct Install ("CDI") Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less; CDI has achieved 511 GWhs of energy savings since its inception in 2008.

Home Energy Improvement Program. The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading/retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the neediest customers.

Refrigerator Exchange Program. The Refrigerator Exchange Program ("REP") is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities, multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third party contractor, ARCA (Appliance Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 106 GWhs since 2007.

LED Streetlight Program. The LED streetlight program provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this model is being expanded with a new $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

Program Analysis and Development Program. The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio, which are not included in individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California. Since the results of the studies, the Department has been crafting incentives for customers to electrify building end uses leveraging existing program delivery mechanisms to promote electric space and water heating, cooking and drying that have traditionally used natural gas as a fuel. While building electrification presents an opportunity to produce additional revenue, the Department's activities have been focused on promoting measures that effectively result in net utility bill reduction (inclusive of gas and electricity). This is directed towards maintaining a high level of customer benefit and satisfaction.

The Department has also partnered with the NREL to develop a technology prioritization tool as the Department ramps up its technology assessment efforts in the Emerging Technologies program. The tool helps prioritize the most impactful technologies that would improve energy efficiency for customers. These technology assessment efforts in the Emerging Technologies program incorporate many of the tools and methods used in the LA100 Study. See "THE POWER SYSTEM – LA100 Study" above.

The set of tools and methods used in the LA100 Study allows the Department to assess potential impacts as it relates to an emerging technology using the development of the building demand modeling that includes baseline consumption and characteristics data for residential and commercial building stock. This effort will analyze multiple use cases to empower the Department to provide more accurate potential studies and develop a pipeline of new technology assessments to determine the appropriate intervention required to get maximum benefits. The goal is to quantify achievable contributions towards goals set by State and local energy policies for the lowest cost.

From 2000 through December 2023, the Department has spent approximately $1.7 billion on its energy efficiency programs, and these programs are estimated to have reduced long-term peak period demand and consumption by approximately 970 MW and resulted in approximately 5,673 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers are estimated to have saved approximately 328 GWhs incrementally for the Fiscal Year 2022-23, falling short of energy savings targets by 89 GWhs. The Department spent approximately $138 million on energy efficiency programs for Fiscal Year 2022-23 of its approximately projected $190 million budgeted amount for such Fiscal Year. The Department will continue to evaluate the delivery and implementation of energy efficiency measures that support system reliability and resiliency while enabling customers to manage their power better. The Department anticipates increasing its expenditures for energy efficiency and building electrification programs in future years, based on portfolio planning utilizing the results of the Department's energy efficiency and building electrification potential studies.

Fuel Supply for Department-Owned Generating Units and Apex Power Project

Natural gas is used to fuel 100% of the Los Angeles Basin Stations. The Department's fossil fuel requirements for the Los Angeles Basin Stations to meet the electric load requirements of its customers in the City (referred to as "native load") were 64 billion equivalent cubic feet of natural gas during Fiscal Year 2022-23. In addition, the Department's fossil fuel requirements for the Apex Power Project were 18 billion equivalent cubic feet of natural gas during Fiscal Year 2022-23. In the early 2000s, the Department determined that acquiring natural gas reserves was advantageous, reasonable and prudent to ensure stable, long-term natural gas supplies to help meet future power generation demands. In June 2005, the Department, the Turlock Irrigation District and SCPPA (acting on behalf of its member California cities of Anaheim, Burbank, Colton, Glendale and Pasadena) acquired rights in natural gas-producing properties from the Anschutz Pinedale Corporation. Under the acquisition agreement, the Department obtained an approximately 74.5% ownership interest in a $300 million acquisition of leases of gas-producing property in Sublette County, Wyoming. This acquisition provided approximately 2.01% of the Department's average daily natural gas requirements for Fiscal Year 2022-23. No increase to this natural gas-producing program is expected at this time, however further capital investment in such program will be re-evaluated if market conditions change and the price of natural gas rises.

The Department obtains its remaining natural gas requirements through a competitively bid spot purchase program or through forward physical gas purchases for a specified period of time. The price of natural gas delivered into Southern California has fluctuated over the past few years and the Department expects prices to continue to fluctuate. To mitigate the effects of natural gas price volatility, the Department includes as part of the Electric Rates certain pass-through cost adjustments that provide recovery of natural gas and other fuel costs. See "ELECTRIC RATES – Rate Setting." In addition, the City Council enacted an ordinance to authorize the Department to enter into financial hedge contracts with respect to natural gas purchases to stabilize fuel costs for native load. See "Note (8) Derivative Instruments" of the Department's Power System Financial Statements. Under this ordinance, the Department's General Manager also may enter into biogas supply agreements for a period not to exceed ten years, so long as certain conditions are met. The use of natural gas swaps, derivatives and other price hedging arrangements are subject to risk management policies and review procedures established by the Board. The Department has developed a natural gas procurement strategy that includes a program of entering into financial hedges with various counterparties that have permitted terms of up to ten years and are intended to mitigate customer exposure to gas price volatility. The policy permits up to 75% of the Department's natural gas requirements to be hedged through various measures (including such financial hedges), although the amount hedged in a given year may vary.

As of December 31, 2023, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2028-29 with an aggregate notional amount of approximately 86.2 million MMBtus. These financial hedges cover up to approximately 41% of the Department's natural gas requirements based on the latest budget for the Fiscal Years through 2028-29. Tables describing the notional amount for each Fiscal Year and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with such hedges as of June 30, 2023 and 2022, can be found in Note (8).

The Department has previously used a physical delivery natural gas hedge program that was designed to hedge up to 50% of its forecasted usage. However, due to the limitation of gas injections at the SoCalGas Aliso Canyon storage facility, there is some uncertainty about intrastate gas transmission capacity available for electric generators. Consequently, the Department reduced the amount of forward physical gas purchased and limited the term of forward purchases based on the Department's quarterly term plan forecasting periods.

The Department has firm interstate natural gas transportation capacity on the Kern River Pipeline System. The total amount of capacity is sufficient to transport 92% of the average amount of natural gas needed for the Los Angeles Basin Stations under current Department forecasts. Additional interstate pipeline capacity, if needed, is acquired through federally-approved capacity brokering programs or through gas purchases bundled with interstate transportation delivered into the SoCalGas intrastate system.

Intrastate transportation and balancing services are provided to the Department by SoCalGas sufficient to meet 100% of the Los Angeles Basin Stations' requirements under SoCalGas's Basic Transportation Service program ("BTS"). This enables the Department to deliver Kern River Pipeline System gas to the BTS receipt points in the State.

As of December 31, 2023, approximately 39% and 38% of the Department's projected natural gas needs have been hedged for Fiscal Year 2024-25 and Fiscal Year 2025-26, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2028-29, approximately 2% of projected natural gas needs are hedged. The Department typically hedges a higher percentage of its natural gas needs as the operating year approaches. The goal of the current natural gas hedging program is to hedge up to five years forward from the current Fiscal Year, with the next Fiscal Year hedged up to 50% and the fifth Fiscal Year hedged up to 10%. The Department periodically reviews the goals of its natural gas hedging program.

The SoCalGas Aliso Canyon underground natural gas storage facility in the Porter Ranch area of Los Angeles leaked between October 23, 2015 and February 18, 2016 and was ordered to cease its injections by State agencies until testing of all operating wells has been completed. The volume in this storage field, SoCalGas's largest, was reduced for safety reasons to a maximum of only 41 billion cubic feet ("BCF"), from its design maximum of 86 BCF. Although the required safety inspections are ongoing, the CPUC has allowed limited operation at Aliso Canyon to maintain gas pipeline and bulk electric system operational reliability. In August 2019, the CPUC approved a revision of the Aliso Canyon Withdrawal Protocol, removing the designation of "facility of last resort," allowing SoCalGas more flexibility to withdraw from the storage field to maintain pipeline integrity. Since this change in policy, SoCalGas has been able to withdraw from the storage field more freely, thus reducing the volatility in both the volume of locally available natural gas and local natural gas pricing. In August 2023, the CPUC approved an increase in the allowable storage at the facility to 68.6 BCF.

There have been no localized natural gas curtailments impacting the Department and there have been no impacts to the Department from SoCalGas operations thus far. With the CPUC's August 31, 2023 vote to increase the Aliso Canyon interim storage limit, the agency also ended SoCalGas's need to comply with the Aliso Canyon Withdrawal Protocol as part of the implementation of that decision. In reaching its August decision, the CPUC determined that "restrictions on Aliso Canyon contributed to last year's natural gas price spikes and that removal of the Commission's storage level limitation provides a significant tool to mitigate future gas price spikes. To effectively implement this decision, the [CPUC] Energy Division is removing the Withdrawal Protocol to allow customers increased flexibility to use Aliso Canyon to moderate gas and electricity prices."

Water Supply for Department-Owned Generating Units

Water required for the operation of generating stations owned by the Department is secured from a number of sources. The Harbor Generating Station, Haynes Generating Station and Scattergood Generating Station use Pacific Ocean water for power plant cooling purposes. However, the Department is undertaking a long-term program of replacing the coastal generating units to eliminate the use of ocean water at these three locations in part to meet requirements of the SWRCB and the City's plans to eliminate the future use of once-through-cooling for these plants and replace them with clean energy alternatives. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station."* The Valley Generating Station, which is located inland, utilizes recycled water for cooling.

Spot Purchases

The Department purchases energy from the Bonneville Power Administration ("BPA") and other Pacific Northwest utilities under short-term "spot" arrangements to be delivered over the Pacific DC Intertie. For further information on the Pacific DC Intertie, see "– Transmission and Distribution Facilities – *Pacific DC Intertie and Sylmar Converter Station*." These purchases are used by the Department in conjunction with other resources for Power System operation. In addition, purchases of energy are made from other entities located in the Southwest. Spot purchases have generally been made at prices that permit economical operation of the Power System and that are comparable to the Department's costs for producing power from its own resources.

The availability of economical energy on the spot market has fluctuated greatly in recent years. Historically, the Department has not been dependent on such purchases to meet its customers' requirements. Although the Department currently continues to find economical spot purchase opportunities (including some for renewable energy), it cannot predict the future availability of power from either the Pacific Northwest or the Southwest for purchases at prices below the Department's costs for producing power from its own resources. The Department has increased its volume activity with the Cal ISO, including the purchase and sale of energy, as well as providing ancillary services, when excess capacity exists on its system.

Cogeneration and Distributed Generation

Currently thermal cogeneration installed in the Department's service area consists primarily of cogeneration projects of industrial and commercial customers. This totals approximately 322 MW nameplate capacity. Some cogeneration projects sell excess energy to the Department under interconnection agreements.

Distributed generation (the generation of electricity at or near the point of use) within the Department's service area currently consists primarily of cogeneration projects at customer facilities. Distributed generation also includes smaller generating units such as solar photovoltaic cells, fuel cells, micro-turbines and other smaller combustion engines. The Department manages a new technology demonstration program to assess the viability of some of these technologies. The Department also supports the development of new technologies through customer incentive programs. See "– Renewable Power Initiatives" and "– Energy Efficiency." These technology advancements may change the nature of energy generation and delivery and may materially affect the operating and financial position of the Department. For example, behind-the-meter resources such as cogeneration, demand response, and energy efficiency may have the effect of reducing customer demand, potentially diminishing revenue for the Department. On the other hand, if such resources are able to be successfully deployed during peak demand hours, this could reduce the Department's need to procure additional utility-scale resources to meet that peak demand.

Excess Capacity

The Department uses its extensive transmission network to sell excess generating capacity into the California, Northwest and Southwest energy markets. Net income from those sales is used to reduce costs to the Department's retail customers (primarily by applying revenues to the costs of capital improvements or toward an electric rate stabilization account in the Incremental Electric Rate Ordinance). With equipment outages, retirement of equipment, anticipated load growth and changes in GHG regulations which impact emission allowances, the Department anticipates that revenue from excess energy sales will be less certain than in the past. Wholesale revenues, as shown in "SELECTED FINANCIAL INFORMATION" under "OPERATING AND FINANCIAL INFORMATION – Financial Information," have accounted for less than 2% of overall Power System revenues in recent years.

Transmission and Distribution Facilities

Electricity from the Department's power generation sources is delivered to customers over a complex transmission and distribution system. To deliver energy from generating plants to customers, the Department owns and/or operates over approximately 15,000 miles of alternating current ("AC") and direct current ("DC") transmission and distribution circuits operating at voltage classes ranging from 120 volts to 500 kV, of which over approximately 11,000 miles are above ground. In addition to using its transmission system to deliver electricity from its power generation resources, under the OATT the Department transmits energy for others through such system when surplus transmission capacity is available and such transmission is permitted by the Master Resolution. As the operating agent of the Pacific DC Intertie, the Southern Transmission System, the Mead-Adelanto Transmission Project and certain Navajo-McCullough transmission facilities (all such facilities being described below), the Department, at the direction of and for the benefit of the respective co-owners/participants, transmits energy for the co-owners of, or participants in, these facilities.

Pursuant to AB 1890, signed into law on January 1, 1997, as part of the deregulation of the State electric industry, municipal utilities such as the Department were encouraged, but not required, to transfer operational control of their electric transmission facilities to the Cal ISO. The Department owns and operates in excess of 25% of the transmission facilities in the State. While the Department has not transferred operational control of its transmission facilities to the Cal ISO, the Department interacts with the Cal ISO on a regular basis. The Department serves as the scheduling coordinator for the delivery of that portion of the Department's energy that requires use of any part of the Cal ISO grid. The Department also coordinates with the Cal ISO with respect to some lines that are jointly owned by the Department and others. The Department is responsible for the costs associated with its use of the Cal ISO grid. The Department is registered as a participant in wholesale transactions in the Cal ISO market.

On April 1, 2021, the Department began participating in Cal ISO's Western EIM. The Western EIM is a real-time energy market that provides sub-hourly dispatch of participating resources for balancing supply and demand every five minutes, using the least-cost energy. As a Western EIM participant, the Department voluntarily provides excess energy capacity for dispatching to other participating utilities, while maintaining control of its generation assets and ratemaking authority. The Western EIM also provides an opportunity for the Department to purchase low-cost excess energy. The Department is participating voluntarily in order to tap into resources across a larger geographic area that includes eleven western states and the Canadian Province of British Columbia. Through its participation, the Department has experienced benefits from purchasing low cost energy during periods of high generation from renewables, a reduction in GHG emissions, as well as financial benefits from selling energy to the market during periods of low supply and higher prices. This helps lower the cost of delivery of power to its customers, and foster integration of renewable energy.

Legislation considered from time to time by the U.S. Congress and the State could potentially increase the level of jurisdictional control over the generation, transmission and distribution assets that comprise the Department's Power System and could encourage voluntary participation by the Department in a regional transmission organization. The City opposes any participation in a regional transmission organization that would be mandatory. The Department monitors any potential restrictions regarding control of transmission rates, authority to finance the Power System using bonds and use of the Power System to deliver electric power to the City.

Certain transmission facilities available to the Department are discussed below.

Southern Transmission System. The Southern Transmission System (the "STS") is an approximately 490-mile, ±500 kV DC transmission line from the Intermountain Generating Station, near Delta, Utah, to Adelanto, California, together with an AC/DC converter station at each end of the line. The STS is owned by IPA and is one of three major components of the IPP. See "– Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*." After the completion of an upgrade to its capacity in December 2010, a maximum of 2,400 MW can be transmitted over the STS. The Department's entitlement in the capacity of the STS is currently approximately 1,428 MW and is expected to increase to 2,172 MW in 2027 as a result of the Department increasing its share of the STS to 90.5% in accordance with the IPP Renewal Power Sales Contract. IPA is undertaking an approximately $2.7 billion renewal project to refurbish or replace the existing Adelanto Converter Station and Intermountain Converter Station with new HVDC stations on available land adjacent to the existing converter stations at Adelanto and IPP, which replacement components are currently scheduled for commercial operation from May 2024 through April 2028. The new converter stations will tie into the existing AC switchyards and connect to the existing DC transmission line. The schedule and cost estimate for the STS renewal project reflect design changes authorized by the IPA board of directors in November 2023 to facilitate an increase in the capacity of the STS from 2,400 to 3,000 MW to be undertaken in the future. The Department entered into a transmission service contract with SCPPA in 1983 to define the terms for transmission service on a "take-or-pay" basis for the Department's 59.5% entitlement right to capacity in the STS that it assigned to SCPPA in order for SCPPA to incur indebtedness sufficient to generate funds to finance the original construction of the STS. This service provides for the transmission of energy from the Intermountain Converter Station to the Adelanto Converter Station until 2027. The Department has negotiated a renewal transmission service contract with SCPPA for the same purpose as the original transmission service contract on a "take-or-pay" basis to allow SCPPA to be able to continue handling financings of the STS (including financing for costs of the ongoing upgrades to the Switchyard and converter station replacements) for the remainder of the term of the Department's participation in the IPP until 2077. SCPPA has issued bonds to finance a portion of the costs of the STS renewal project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Northern Transmission System. The Northern Transmission System (the "NTS") includes two approximately 50-mile, 345 kV AC transmission lines from IPP to the Mona Substation in Northern Utah, and one approximately 144-mile, 230 kV AC transmission line from IPP to the Gonder Substation in Nevada. The NTS was constructed for the delivery of power from IPP to certain municipalities in Utah and certain cooperative purchasers. Capacity on the NTS is available to the Department through the IPP Excess Power Sales Agreement. The Department can have up to a maximum NTS share allocation of 43.141% of the total capacity depending on the generation deemed excess by the 29 Utah municipalities and cooperatives that have access to such power. The capacity from IPP to Mona is 1,400 MW; the capacity from Mona to IPP is 1,200 MW; the capacity from IPP to Gonder is 200 MW; and the capacity from Gonder to IPP is 117 MW.

Pacific DC Intertie and Sylmar Converter Station. The Pacific DC Intertie is an approximately 846-mile, ±500 kV DC transmission system that connects Southern California to the hydroelectric and wind generation resources of the Pacific Northwest. A maximum of 3,210 MW can be transmitted over the entire Pacific DC Intertie System. The Department owns a 40% interest in the southern portion of the Pacific DC Intertie from the Nevada-Oregon border to its southern terminus at the Sylmar Converter Station in Sylmar, California and is the operating agent of the southern portion of the Pacific DC Intertie. The northern portion of the Pacific DC Intertie is owned and operated by BPA and extends from the Nevada-Oregon border to BPA's Celilo Station in The Dalles, Oregon.

Devers-Palo Verde Transmission Line. The Devers-Palo Verde Transmission Line is an approximately 250-mile, 500 kV AC line owned by Edison that connects the PVNGS with the Devers Substation outside Desert Hot Springs, California. As part of an exchange agreement, the Department purchases up to 368 MW of bi-directional firm transmission service on the Devers-Palo Verde Transmission Line from Edison (the "Devers-Palo Verde Agreement") at the rate being charged by the Cal ISO for that same service. The Devers-Palo Verde transmission path now consists of the Devers-Colorado River and Colorado River-Palo Verde transmission lines. The Department has the right to terminate the service upon 12 months written notice.

Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission project is an approximately 259-mile, 500 kV AC transmission line which originates at the Westwing substation in Phoenix, Arizona, connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace substation nearby. The Mead-Phoenix Transmission Project is currently owned by SCPPA, APS, Salt River Project, Western and Startrans IO, L.L.C. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Phoenix Transmission Project for the benefit of the Department through the purchase of the M-S-R Public Power Agency ("M-S-R") ownership share (11.5385% of the Westwing-Mead component and 8.09930% of the Mead-Marketplace component) of the Mead-Phoenix Transmission Project. After such acquisition, the Department's share is 57.732% of SCPPA's member-related interests in the Westwing-Mead component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 29.8462% of the entire Westwing-Mead component of the Mead-Phoenix Transmission Project) and 39.6459% of SCPPA's member-related interests in the Mead-Marketplace component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 30.5075% of the entire Mead-Marketplace component of the Mead-Phoenix Transmission Project). A maximum of 1,923 MW can be transmitted over the Westwing-Mead component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 332 MW. A maximum of 2,600 MW can be transmitted over the Mead-Marketplace component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 315 MW. The Department's average share of the Mead-Phoenix Transmission Project components is 50.39% of SCPPA's member-related interests in the Mead-Phoenix Transmission Project. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Phoenix Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Phoenix Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Phoenix Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project is an approximately 202-mile, 500 kV AC transmission line between the Adelanto substation, near Victorville, California and the Marketplace substation, near Boulder City, Nevada. The Mead-Adelanto Transmission Project was constructed by its owners, currently, SCPPA, Western and Startrans IO, L.L.C., in connection with the Mead-Phoenix Transmission Project. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Adelanto Transmission Project for the benefit of the Department through the purchase of M-S-R's 17.5% ownership share of the Mead-Adelanto Transmission Project. After such acquisition, the Department's share is 48.878% of SCPPA's member-related interests of the Mead-Adelanto Transmission Project (SCPPA's member-related interests comprise 85.4167% of the entire Mead-Adelanto Transmission Project). A maximum of 1,291 MW can be transmitted over the Mead-Adelanto Transmission Project, of which the Department has an entitlement share of 539 MW. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Adelanto Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Adelanto Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Adelanto Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Navajo-McCullough Transmission Line. The Navajo-McCullough Transmission Line is a 274-mile, 500 kV AC transmission line that originates at the Navajo Project near Page, Arizona, connects through the Crystal Substation near Las Vegas, Nevada and terminates at the McCullough substation, near Boulder City, Nevada. The Department owns 48.9% of the Navajo-McCullough Transmission Line, which was constructed as a part of the now-retired Navajo Generating Station. The Crystal Substation was constructed by NV Energy. NV Energy owns 100% of the Crystal Substation on behalf and for the benefit of the Navajo Project, including the Department.

Eldorado Transmission System. The Eldorado Transmission System's major components are the 59-mile, 500 kV AC Mohave-Eldorado transmission line, the 500 kV Mohave Switchyard, the Eldorado substation, which is comprised of a 220 kV switchyard and a 500 kV switchyard, and two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines. Pursuant to a Co-Tenancy and Operating Agreement, the Department is a 30% co-owner of the Mohave Switchyard, a 29.3% co-owner of the 500 kV switchyard, an 11.3% owner of the 220 kV switchyard, and a 15.1% co-owner of the transformers between the 500 kV and 220 kV switchyards, each of which is a part of the Eldorado Substation. The Department's ownership represents 716 MW of capacity on the Mohave-Eldorado transmission line and 215 MW of capacity on the two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines.

Barren Ridge Renewable Transmission Project. The Barren Ridge Renewable Transmission Project involved the expansion of the Barren Ridge Switching Station in order to increase the 3,119 MVA transmission capacity of renewable energy flowing into the Los Angeles Basin from generating facilities in Owens Valley, Kern County and the Tehachapi Mountains by 2,000 MVA.

Projected Capital Improvements

The Department has developed a series of Power System resource plans with each plan updating and refining the previous plan. The plans are developed in conjunction with the Department's strategic planning to meet its goals of continuing to provide reliable service to customers, maintaining a competitive price for the Power System's services and providing environmental leadership. Such resource plans act as guidance for the Department in implementing more specific short-term and long-term financial plans.

Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten-year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department achieved its energy efficiency goal of 15% energy efficiency savings by 2020 and is now focused on an additional 3,431 GWhs of energy savings by 2035. Enhancement and expansion of electric transmission resources will enable access to renewable energy resources. Certain in-basin energy projects will assist in integrating intermittent renewable resources into the Power System. Capital investments in the transmission and distribution system, including new business service and electric feeder lines, are required to support future growth. New control and monitoring systems are needed to continue to provide reliable and secure system operations. See " – Power System Reliability Program" below.

Power System Reliability Program. A significant power outage in 2006 caused the Department to conduct an evaluation of its electrical infrastructure and led to the development of a comprehensive distribution-focused power reliability program initially referred to as the "Power Reliability Program" with the following major components: (a) mitigation of problem circuits and stations based on the types of outages specific to the facility, including among other things, timely, permanent repairs of distribution circuits after a failure and fixing poorly performing circuits, (b) proactive maintenance and capital improvements that take into account system load growth and the inspections and routine maintenance that must take place to identify problems before they occur, (c) replacement cycles at the facilities that are in alignment with the equipment's life cycle such as replacing aging underground cables, overhead poles and circuits and substation equipment and (d) replacement of overloaded transformers. In 2013, another evaluation was completed and the program was expanded and renamed the "Power System Reliability Program." The Power System Reliability Program assesses all Power System assets affecting reliability in an integrated and comprehensive manner and proposes corrective actions as well as capital expenditures designed to minimize future outages and maintain reliability in the short and long term. The Power System Reliability Program includes the establishment of metrics and indices to help prioritize infrastructure replacement and expenditures for all major functions of the Power System, including distribution, transmission, generation, and substations. The Power System Reliability Program has been and is anticipated to be updated on an annual basis to adjust to varying Power System conditions and resource allocations.

Projected Capital Expenditures. As indicated in the table on the following page, for Fiscal Year 2023-24 through Fiscal Year 2027-28, the Department expects to invest approximately $13.5 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2023
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$1,926
IT Infrastructure*	553
Energy Efficiency	972
Power System Reliability Program	5,479
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	2,752
Power System Resource Plan	7
Shared Services: Facilities, Customer Services, Fleet	1,842
Total Power System Capital Improvements	$13,531

* For planning purposes, the power financial plan includes a proposed IT Cost Adjustment Factor (ITCAF) with an effective date of July 1, 2024. This proposed ITCAF is designed to recover the information technology (IT) expenses related to enterprise resource planning, smart grid, cybersecurity, and cloud infrastructure programs. These IT expenses include both capital and operation and maintenance expenses that are being allocated among base revenue supported categories such as operating support, infrastructure and other pass-through supported categories.

Source: Department of Water and Power of the City of Los Angeles.

The table below indicates, for Fiscal Year 2023-24 through Fiscal Year 2027-28, the expected funding sources for the capital improvements to the Power System expected for such Fiscal Years.

EXPECTED FUNDING SOURCES FOR CAPITAL IMPROVEMENTS
TO THE POWER SYSTEM
(in Millions)

Fiscal Year Ending (June 30)	Internally Generated Funds	External/Debt Financing	Total Capital Expenditures[(1)]
2024	$1,745	$ 422	$2,167
2025	869	1,697	2,566
2026	1,133	1,144	2,277
2027	1,350	1,479	2,829
2028	1,217	2,475	3,692
	$6,314	$7,217	$13,531

Source: Department of Water and Power of the City of Los Angeles.
(1) Net of reimbursements to the Department.
Note: Total may not equal sum of parts due to rounding.

The particular programs and commitments for capital improvements to the Power System are subject to review by Department stakeholders and others. The estimated costs of, and the projected schedule for, the expected capital improvements to the Power System and the Department's other capital projects are subject to a number of uncertainties. The ability of the Department to complete such capital improvements may be adversely affected by various factors including: (i) estimating errors, (ii) design and engineering errors, (iii) changes to the scope of the projects, (iv) delays in contract awards, (v) material and/or labor shortages, (vi) unforeseen site conditions, (vii) adverse weather conditions, (viii) contractor defaults, (ix) labor disputes, (x) unanticipated levels of inflation, (xi) environmental issues, (xii) the ability to access the capital markets at particular times and (xiii) delays in approvals of rate increases. No assurance can be given that the proposed projects will not cost more than the current budget for these projects. Any schedule delays or cost increases could result in the need to issue additional obligations and may result in increased costs to the Department. All payments of project costs associated with projected capital improvements are subject to Board approval.

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OPERATING AND FINANCIAL INFORMATION

The Department's service area consists of the City, where over 1.5 million customers are served, and certain areas of Inyo and Mono Counties in the State, where approximately 5,213 customers are served. As of December 31, 2023, 33% of the Power System's total energy sales (measured in MWhs) were to residential customers, 64% to commercial and industrial customers and the remaining 3% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately 34%, 61%, and 5% of total revenue, respectively.

Summary of Operations

The table below provides certain operating information with respect to the Power System.

POWER SYSTEM
SELECTED OPERATING INFORMATION
(Unaudited)

Operating Statistics	Six Month Period Ended December 31		Fiscal Year Ended June 30				
	2023[1]	2022	2023	2022	2021	2020	2019
Net Energy Load[2]	12,313	13,218	23,859	23,997	23,797	24,096	25,046
Net Hourly Peak Demand (MW)	5,453	6,216	6,216	4,911	6,106	5,637	6,201
Annual Load Factor (%)	51.12	48.14	43.81	55.79	44.49	48.66	46.11
Electric Energy Generation, Purchases and Interchanges[2]							
Generation[3][4]	8,885	9,360	17,172	17,194	17,281	17,947	16,862
Purchases[2]	4,385	5,313	9,148	9,440	8,988	7,295	8,966
Miscellaneous Energy Receipts[2]	–	–	–	–	705	470	230
Total Energy[2]	13,270	14,673	26,320	26,634	26,974	25,712	26,058
Less:							
Miscellaneous Energy Deliveries[2][5]	266	230	426	511	–	–	–
Losses and System Uses[2]	1,296	1,339	2,386	2,595	4,479	3,879	3,507
On-System Sales[2]	11,708	13,104	23,508	23,528	22,495	21,833	22,550
Sales of Energy[2]							
Residential	3,845	4,345	7,736	7,383	7,707	7,218	7,303
Commercial and Industrial	7,302	7,504	13,959	14,092	13,220	14,030	14,661
All Other	301	1,018	1,722	1,891	2,087	1,050	626
Total	11,448	12,867	23,417	23,366	23,014	22,298	22,590
Number of Customers – (Average, in thousands):							
Residential	1,448	1,434	1,440	1,430	1,414	1,405	1,397
Commercial and Industrial	128	128	128	128	126	126	126
All Other	7	7	7	7	7	7	7
Total	1,583	1,569	1,575	1,565	1,547	1,538	1,529

Source: Department of Water and Power of the City of Los Angeles.

(1) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(2) Thousands of MWhs.

(3) Does not include energy generated at Hoover Power Plant for plant use and for the use of the Bureau of Reclamation and the cities of Boulder City, Nevada; Burbank, California; Glendale, California and Pasadena, California.

(4) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.

(5) Deliveries include transmission loss energy paybacks and control area inadvertent interchange.

Financial Information

The tables below provide certain financial information with respect to the Power System.

POWER SYSTEM
SELECTED FINANCIAL INFORMATION
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31		Fiscal Year Ended June 30[1]				
	2023[2]	2022	2023	2022	2021	2020	2019
Operating Revenues							
Residential	$ 798,930	$ 880,847	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and Industrial	1,402,753	1,391,442	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale[3]	106,632	180,680	326,347	230,160	186,706	61,455	111,542
Other[4]	4,260	11,652	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$2,312,575	$2,464,621	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Average Revenue per kWh Sold[5]							
Residential	0.208	0.203	0.222	0.222	0.209	0.189	0.188
Commercial and Industrial	0.192	0.185	0.205	0.198	0.189	0.169	0.175
Average Annual Residential Usage[6]	3	3	5	5	5	5	5
Operating income	$ 317,206	$ 365,377	$ 742,176	$ 800,988	$ 744,139	$ 363,981	$ 512,310
As % of revenues	13.7%	14.8%	15.0%	17.4%	17.4%	9.6%	12.6%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[7]	$ 319,966	$ 377,130	$ 833,815	$ 532,290	$ 633,942	$ 320,065	$ 459,503
Adjusted Change in Net Position, including Power Transfer and accounting change[7]	$ 75,271	$ 145,087	$ 601,772	$ 307,275	$ 415,587	$ 90,152	$ 226,946

Source: Department of Water and Power of the City of Los Angeles.

(1) Derived from the Power System Financial Statements (except for usage statistics).

(2) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(3) Includes sales of power and transmission services to other utilities.

(4) Net of Uncollectible Accounts.

(5) The calculated Average Revenue per kWh Sold is based on dividing reported Operating Revenues by customer class by volumes for that customer class, including deferred revenues. The actual customer rates may differ from these calculated figures due to a variety of factors, including (1) demand and energy charges for commercial rates, (2) changes in usage between rate tiers within a customer class and between years, and (3) other factors including customer classification issues.

(6) MWh use per residential customer.

(7) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements. Adjustments reflect the impact of the implementation of new accounting standards, particularly GASB No. 75, which resulted in the recording of certain OPEB liabilities and a corresponding reduction in net position.

POWER SYSTEM
SUMMARY OF REVENUES, EXPENSES AND DEBT SERVICE COVERAGE
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31		Fiscal Year Ended June 30[1]				
	2023[2]	**2022**	**2023**	**2022**	**2021**	**2020**	**2019**
Operating Revenues							
Sales of Electric Energy:							
Residential	$ 798,930	$ 880,847	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and industrial	1,402,753	1,391,442	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale	106,632	180,680	326,347	230,160	186,706	61,455	111,542
Other[3]	4,260	11,652	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$2,312,575	$2,464,621	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Operating Expenses							
Production:							
Fuel for Generation	$ 197,839	$ 297,402	$ 435,524	$ 327,813	$ 228,697	$ 207,043	$ 296,506
Purchased Power	584,545	704,781	1,448,692	1,309,505	1,301,394	1,242,068	1,264,133
Energy Cost	782,384	1,002,183	1,884,216	1,637,318	1,530,091	1,449,111	1,560,639
Maintenance and Other Operating Expenses	822,356	724,113	1,570,429	1,430,993	1,323,158	1,364,303	1,412,750
Adjusted Operating Expenses[4][6]	$1,604,740	$1,726,296	$3,454,645	$3,068,311	$2,853,249	$2,813,414	$2,973,389
Adjusted Operating Income[4][6]	$ 707,835	$ 738,325	$1,503,894	$1,525,449	$1,415,229	$ 993,877	$1,097,541
Other non-operating income and expenses, net	172,527	168,987	413,808	1,482	145,303	268,502	239,211
Contributions in aid of construction	30,706	42,508	76,942	100,865	103,459	57,692	58,373
Adjusted Change in Net Position[5][6]	$ 911,068	$ 949,820	$1,994,644	$1,627,796	$1,663,991	$1,320,071	$1,395,125
Debt Service							
Adjusted Interest[6][7]	262,826	257,372	517,818	479,482	459,413	454,074	426,577
Principal	214,040	190,315	190,315	187,683	179,405	171,925	153,664
Total debt service	$ 476,866	$ 447,687	$ 708,133	$ 667,165	$ 638,818	$ 625,999	$ 580,241
Debt Service Coverage Ratio	N/A	N/A	2.82	2.44	2.60	2.11	2.40
Depreciation, amortization and accretion	$ 390,629	$ 372,948	$ 761,718	$ 724,461	$ 671,090	$ 629,896	$ 585,231
Transfers to the Reserve Fund of the City	$ 244,695	$ 232,043	$ 232,043	$ 225,015	$ 218,355	$ 229,913	$ 232,557

Source: Department of Water and Power of the City of Los Angeles.
(1) Derived from the Power System Financial Statements.
(2) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.
(3) Net of Uncollectible Accounts.
(4) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.
(5) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.
(6) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements.
(7) Interest expense excluding amortization of debt premium.

Indebtedness

*{update to come}*As of [February 1], 2024, approximately $[11.32]billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $[9.98] billion in principal amount is fixed-rate bonds and approximately $1.34 billion in principal amount is variable-rate bonds. In connection with the Department's five-year capital improvements to the Power System, the Department anticipates that it will issue approximately $7.2 billion of debt through June 30, 2028 payable from the Power Revenue Fund. See "THE POWER SYSTEM – Projected Capital Improvements" and "Note (9) Long-Term Debt" of the Department's Power System Financial Statements.

Certain of the Department's outstanding debt are "federally subsidized direct-pay" bonds, for which, instead of the interest being tax-exempt, the Department receives a subsidy payment from the Treasury Department equal to 35% of the interest paid or up to 70% of the tax credit rate determined by the Treasury Department, depending on the type of federally subsidized direct-pay bonds. Pursuant to certain federal budget legislation adopted in August 2011, starting as of March 1, 2013, the government's subsidy payments were reduced as part of a government-wide "sequestration" of many program expenditures. The amount of the reduction of the subsidy payment has ranged from a high of 8.7% in 2013 to a low of 5.7% for federal fiscal years 2021 through 2031. The amount of this reduction for the Power System has been less than $1.5 million annually and such reductions are presently scheduled to continue through September 30, 2031.

Congress can terminate, extend, or otherwise modify reductions in subsidy payments due to sequestration at any time. In addition, under the Statutory Pay-As-You-Go Act of 2010, an increase in the federal deficit caused by a new tax or entitlement spending law could trigger further sequestration reductions to non-exempt mandatory spending programs, absent a waiver either as part of the triggering law or in subsequent legislation. If the sequestration reduction rate were to increase to 100%, the reduction in subsidy payments for the Power System would currently be approximately $[25.5] million annually. *{update to come}*

On May 25, 2023, the Department entered into a revolving credit agreement (the "Wells RCA") with Wells Fargo Bank, National Association ("Wells Fargo") in a principal amount not-to-exceed $300 million outstanding at any one time; provided that the Department can request that Wells Fargo increase the available commitment under the Wells RCA by an additional $200 million, with approval of such increase being at the sole discretion of Wells Fargo. As of [February 1], 2024, the Department has no obligations outstanding under the Wells RCA payable from the Power Revenue Fund. As of [February 1], 2024, the Department had $[50] million principal amount outstanding under the Wells RCA payable from the Water Revenue Fund. Under the Wells RCA, which expires on May 22, 2026, amounts due may be paid by the Department at any time at its option and in the event of default under the Wells RCA, amounts outstanding would be due immediately. The Department expects to pay principal amounts due under the Wells RCA payable from the Power Revenue Fund from proceeds of subsequent borrowings or from reserves available to the Power System. Amounts borrowed under the Wells RCA payable from the Power Revenue Fund are considered Parity Obligations under the Master Resolution. The Department does not believe that its obligations with respect to the Wells RCA will result in a default under the Department's other Parity Obligations.

For more information about the Department's variable rate bonds, including their associated liquidity facilities (as applicable), see "Note (10) Variable Rate Bonds" of the Department's Power System Financial Statements.

In addition, as of [February 1], 2024, the Department was obligated on a "take-or-pay" basis under power purchase or transmission capacity contracts for debt service payments (its share representing approximately $[2.46] billion principal amount of bonds) and for operating and maintenance costs of the related projects. The Department has entered into, and may in the future enter into additional, "take-or-pay" contracts in connection with renewable energy projects and other projects undertaken by the joint powers agencies in which it participates. The Department's obligations to make payments under such "take-or-pay" contracts are unconditional payment obligations. See "– Take-or-Pay Obligations" for the "take-or-pay" contracts the

Department has entered as of [February 1], 2024. All such commercial paper and "take-or-pay" contract obligations rank on a parity with the Department's Bonds as to payment from the Power Revenue Fund.

Take-or-Pay Obligations

The Department entered into the IPP Contract and the IPP Excess Power Sales Agreement to purchase up to a 66.79% share of the output of the IPP. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*." The Department is also a member of SCPPA and participates in a number of SCPPA projects, including a number of renewable energy projects. See "THE POWER SYSTEM – Renewable Power Initiatives." The Department's obligations to make payments with respect to the IPP and the SCPPA projects in which it participates are unconditional "take-or-pay" payment obligations, obligating the Department to make such payments as operating expenses of the Power System whether or not the applicable project is operating or operable, or the output thereof is suspended, interfered with, reduced, curtailed or terminated in whole or in part. The IPP Contract, the IPP Excess Power Sales Agreement and the agreements with respect to the SCPPA projects (other than with respect to projects in which the Department is the sole participant) contain certain step-up provisions obligating the Department to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs related to the project and reserves as a result of a defaulting participant. The Department's participation and share of bond debt service obligation (without giving effect to any provisions requiring the Department to contribute to any deficiencies upon default by another participant) as of [February 1], 2024, for each of the foregoing projects are shown in the following table:

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POWER SYSTEM
TAKE-OR-PAY OBLIGATIONS FOR BONDS
As of [February 1], 2024
(Dollars in Millions) ***{update to come}***
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt[6]
Intermountain Power Agency			
IPP	$ 102[1]	48.62%[2]	$ 49[1]
IPP (Renewal Project)	1,531	71.44	1,093
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	16	100.00[3]	16
Mead-Phoenix Transmission Project	13	100.00[3]	13
Linden Wind Energy Project	75	100.00[4]	75
Milford Wind Corridor Phase I Project	76	92.50[5]	70
Milford Wind Corridor Phase II Project	66	100.00[4]	66
Southern Transmission System (STS)	126	59.50[5]	75
STS (Renewal Project)	677	90.50[5]	613
Windy Point Project	162	100.00[4]	162
Apex Power Project	230	100.00[5]	230
Total	$3,074		$2,462

Source: Department of Water and Power of the City of Los Angeles.

(1) Represents a portion of the IPP and SCPPA debt issued to finance costs of the IPP repowering project and STS renewal project, the Department's share of the bond debt service obligation for which is payable in accordance with the terms of, and the Department's participant share under, the IPP Contract prior to the effective date of the Renewal Power Sales Contract in June 2027. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(2) Includes the Department's obligations under the IPP Contract (48.617%) but does not include the Department's obligations under the IPP Excess Power Sales Agreement as described under the caption "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(3) The bonds remaining outstanding relate to the additional interest acquired by SCPPA solely for the benefit of the Department.

(4) Equals the Department's share of SCPPA's and the City of Glendale's entitlements. See "THE POWER SYSTEM – Renewable Power Initiatives."

(5) Equals the Department's share of SCPPA's entitlement.

(6) In addition to outstanding principal, the Department is obligated to pay its share of interest on outstanding debt and annual operating and maintenance costs. See Note (5) in the Department's Power System Financial Statements for additional information.

FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY

The following regulatory programs affect the Department and the electric utility industry and should be considered when evaluating the Department and considering an investment in the bonds. The Department cannot predict at this time whether any additional legislation or rules will be enacted which will affect the Power System's operations, and if such laws or rules are enacted, what the costs to the Department might be in the future because of such action. See "GENERAL," "ELECTRIC RATES," "THE POWER SYSTEM – Projected Capital Improvements," "OPERATING AND FINANCIAL INFORMATION" and the Department's Power System Financial Statements for additional information relating to the Department.

California Climate Change Policy Developments

State regulatory agencies such as CARB and the CEC are pursuing a number of regulatory programs designed to reduce GHG emissions and encourage or mandate renewable energy generation. The following is a summary of certain programs. See also “Environmental Regulation and Permitting Factors” below.

GHG Regulations. In September 2006, the Global Warming Solutions Act was signed into law. This law established the State’s target to reduce Statewide GHG emissions back to 1990 levels by 2020, which represented a reduction of approximately 25% Statewide. In September 2016, SB 32, an amendment to the Global Warming Solutions Act, was signed into law, and established a new target to reduce Statewide GHG emissions 40% below 1990 levels by 2030. In September 2022, AB 1279, the California Climate Crisis Act, was signed into law. AB 1279 establishes a State policy to achieve net zero GHG emissions as soon as possible, but no later than 2045, to achieve and maintain net negative GHG emissions thereafter, and to ensure that by 2045, Statewide anthropogenic GHG emission are reduced to at least 85% below the 1990 levels.

CARB implemented the Global Warming Solutions Act through regulations (the “Cap-and-Trade Regulations”) that imposed a declining economy-wide limit or cap on GHG emissions from major sources within the State, including the electricity generation industry, and allocates the aggregate emissions limit through the distribution of allowances, or emission credits.

The Cap-and-Trade Regulations require all regulated entities, including the Department, to report annual GHG emissions and to obtain and surrender GHG emission allowances and/or offsets for each metric ton of GHG emissions. Cap-and-trade compliance covers GHG emissions from in-state fossil-fueled power plants, as well as imported electricity from out-of-state resources such as the IPP. In addition, the Department may indirectly bear compliance costs for purchased electricity.

The Department, like other electric utilities, receives an administrative allocation of allowances to cover its expected GHG emissions. Entities that emit GHGs at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or from other covered entities with surplus allowances. The Department believes that, if its administrative allowance allocation is not sufficient to cover GHG emissions from all of the Department’s generation and purchases of electricity to serve retail customer load, the Department could obtain additional allowances by participating in the CARB auctions or the secondary market. The Department also believes that the cost of compliance with the Cap-and-Trade Regulations for retail customer load will be substantially covered by the administrative allocation of allowances and/or existing rate adjustments and anticipated rate increases through 2030. When the Department sells electricity in the wholesale market, it is required to purchase allowances to cover GHG emissions for those wholesale electricity sales, and the cost of such allowances is included in the electricity price paid by the wholesale buyer.

In July 2017, CARB adopted amendments to the Cap-and-Trade Regulations, which included a 40% reduction in the Statewide GHG emissions cap between 2021 and 2030. CARB granted administrative allowance allocations to electrical distribution utilities such as the Department for the 2021 to 2030 compliance period. The Power System is expected to be able to continue to comply with these amendments with minimal impact to its finances or operations in connection with the implementation of the Power System’s resource plan.

In July 2017, AB 398 was signed into law to extend the State’s Cap-and-Trade Regulations from 2021 to 2030. The bill cleared both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, CARB was directed to address the following: establish a price ceiling, offer non-tradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance overallocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. AB 398 was passed in conjunction with two companion bills: AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities, and Assembly Constitutional

Amendment No. 1 (“ACA-1”), which created a special Greenhouse Gas Reduction Reserve Fund in the State Treasury, into which all new money collected from the auction of cap-and-trade allowances is to be deposited beginning January 1, 2024 until the effective date of legislation that appropriates money from the fund. The money is then to be appropriated to the existing Greenhouse Gas Reduction Fund, from which money is allocated to 75 California Climate Investment programs administered by 23 State agencies to reduce GHG emission and provide environmental, economic, and public health benefits. A minimum of 35% of California Climate Investments are required to benefit priority populations including disadvantaged communities and low-income communities and households.

In December 2018, CARB approved amendments to the Cap-and-Trade Regulations to make the cap-and-trade program consistent with AB 398 requirements. The amendments to the Cap-and-Trade Regulations went into effect on April 1, 2019. The Department does not expect that its continued compliance with these amendments will have a material adverse effect on the operations or financial condition of the Power System.

In February 2023, CARB issued a market notice regarding further updates to the Cap-and-Trade Regulations. Topics to be considered include banked allowances, evaluation of the program caps within the context of the 2022 Scoping Plan goals, conducting electricity sector and industrial sector leakage studies, updates to offset protocols, addressing the new Extended Day Ahead Market for electricity, protecting low-income households from disproportionate impacts of energy prices, and carbon dioxide sequestration and removal projects developed under the SB 905 Carbon Capture, Removal, Utilization, and Storage Program. CARB has indicated the proposed rule amendments package is expected to be posted for public review and comment in early to mid-2024. *{update to come}*

GHG Emissions Performance Standard and Financial Commitment Limits. Pursuant to SB 1368 (Chapter 598, Statutes of 2006), the CEC adopted a GHG emissions performance standard (“EPS”) for electric generating facilities of 1,100 pounds of CO_2 per MWh for “covered procurements” by POUs, such as the Department. SB 1368 also prohibits POUs from making any “long-term financial commitment” in connection with “baseload generation” that does not satisfy the EPS. Generally, a “long-term financial commitment” is any new or renewed power purchase agreement with a term of five years or more, the purchase of an interest in a new power plant or any investment, other than routine maintenance, in an existing power plant that is designed and intended to extend the life of the plant by more than five years or results in an increase of 50 MW or more in its rated capacity. “Baseload generation” means a power plant that is intended to operate at an annualized capacity factor of 60% or more.

California Renewable Portfolio Standard. The State’s legislature and executive branch have been active in promoting increasingly stringent renewable energy procurement requirements since 2002. Early efforts established a standard of 20% of renewable electricity generation by 2017. Since then, both legislative and executive branch initiatives have raised that standard in multiple phases.

In April 2011, SBX 1-2, the California Renewable Energy Resources Act, was signed into law. SBX 1-2 established procurement targets for three compliance periods (“Compliance Periods 1 through 3”) to be implemented by the procurement plan: 20% of the utility’s retail sales were to be procured from eligible renewable energy resources by December 31, 2013; 25% by December 31, 2016; and 33% by December 31, 2020. The Department met the targets established by SBX 1-2 for each of Compliance Periods 1 through 3.

In October 2015, SB 350 was signed into law, which requires retail sellers and POUs, such as the Department, to make reasonable progress each year to ensure it achieves 40% of retail sales from eligible renewable energy resources by December 31, 2024, 45% of retail sales from eligible renewable energy resources by December 31, 2027, and 50% of retail sales from eligible renewable energy resources by December 31, 2030.

In September 2018, SB 100 was signed into law, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as the Department, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of the State that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to State end-use customers by December 31, 2045. Defining resources that constitute a "zero-carbon resources" will be subject to further regulatory proceedings of the CEC and CARB. The CEC has adopted updates to the RPS Enforcement Procedures for Publicly Owned Utilities which incorporate requirements set forth in SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350 pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of RPS procurement must be from contracts of 10 years or more in duration or in ownership or ownership agreements. The updated regulations became effective on July 12, 2021.

In September 2022, SB 1020 was signed into law SB 1020, which revised the policy of the State established by SB 100 to provide that eligible renewable energy resources and "zero-carbon resources" supply 90% of all retail sales of electricity to State end-use customers by December 31, 2035, 95% by December 31, 2040, 100% by December 31, 2045, and 100% of electricity procured to serve all State agencies by December 31, 2035.

See "THE POWER SYSTEM – Renewable Power Initiatives" and "– Projected Capital Improvements" for a description of the Department's existing and potential renewable energy projects.

Biomass Legislation. In September 2016, SB 859 was signed into law. Among other things, SB 859 required certain electric utilities to enter into five-year contracts for at least 125 MW of biomass capacity with facilities that generate energy from feedstock harvested from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. Due to the specific requirements of the law, the available facilities satisfying the requirements of the law are limited. The Department, SCPPA and the other POUs procured biomass capacity under contracts from two projects to satisfy the SB 859 requirements: (i) the ARP-Loyalton contract that ended in April 2023, from which the Department's contracted amount was 8.9 MW, and (ii) a contract for 5.4 MW of capacity with Roseburg Forrest Products Co., in Weed, California. See "THE POWER SYSTEM – Renewable Power Initiatives – *Biomass Development*."

Energy Storage Legislation. In October 2017, SB 801 was signed into law, which required the Department, by June 1, 2018, to determine the cost-effectiveness and feasibility of deploying a minimum aggregate total of 100 MW of cost-effective energy storage solutions to help address the Los Angeles Basin's electrical system operational limitations resulting from reduced gas deliverability from the Aliso Canyon natural gas storage facility. Department staff performed analysis and found that a 100 MW battery energy storage system paired with solar generation at the grid would be cost effective by 2022. See "THE POWER SYSTEM – Renewable Power Initiatives – *Energy Storage Development*." To comply with such legislation, the Department has entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2.

Renewable Energy Policy Development. In August 2018, the CEC adopted the policy "Toward A Clean Energy Future, 2018 Integrated Energy Policy Report Update" (the "2018 IEPR"). The 2018 IEPR is composed of two volumes. The first volume is a high-level summary of the energy policies the State has implemented in recent years. This high-level summary includes (i) the State's participation in an international pact to reduce emissions and increase renewable electricity procurement to 33% by 2020 and 50% by 2030; (ii) continued support for incentives or mandates for more homes and business to install rooftop solar; (iii) an executive order calling for at least five million zero-emission vehicles on the State's roads by 2030 and an extensive expansion of charging and refueling infrastructure; and (iv) continued support for the development and implementation of an energy efficient program in existing buildings. The second volume provides updated analysis of issues raised in previous Integrated Energy Policy Reports, including "advancing then-Governor Brown's call to expand state adaptation activities through Executive Order B-30-15, with the goal of making the consideration of climate change a routine part of planning," as well as, "enhancing the resiliency of the electricity system while integrating increasing amounts of renewable energy." See "– Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board*" below.

Legislation and Court Action Relating to Wildfires. In September 2016, SB 1028 was signed into law. SB 1028 requires each POU, including the Department, each IOU and each electric cooperative in the State to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 required the governing board of each POU to make an initial determination of whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on historical fires and local conditions. POU governing boards were required to independently make this determination based on all relevant information, including the CPUC's Fire Threat Map which was adopted by the CPUC in January 2018 (discussed below). On September 5, 2018, the Board determined that the Power System's overhead electrical lines and equipment do not pose a significant risk of causing a catastrophic wildfire. Prior to the enactment of SB 1028, the Department has had an active fire prevention plan since 2008, which includes construction standards, a vegetation management program, and an inspection and maintenance program.

SB 901, which was signed into law in September 2018, amends certain provisions of SB 1028. Under SB 901, among other things, POUs, such as the Department, are required to prepare a wildfire mitigation plan, initially before January 1, 2020, and annually thereafter. SB 901 requires the POU to contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator is to be made available to the public and presented at a public meeting of the POU's governing board. Consistent with the requirements of SB 901 and subsequent legislation (AB 1054 discussed below), the Department updates its wildfire mitigation plan on an annual basis, with comprehensive revisions and independent evaluator reviews occurring every three years.

In 2017, the CPUC adopted a work plan for the development and adoption of the CPUC Fire-Threat Map. On the CPUC Fire-Threat Map, any area in a Tier 2 fire-threat area is depicted as an "elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires" and any area in a Tier 3 fire-threat area is depicted as an "extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." Based on the Department's wildfire mitigation plan dated June 2023, approximately 13.8% of the Power System's overhead distribution power lines fall within a Tier 2 area and approximately 0.5% of the Power System's overhead distribution power lines fall within a Tier 3 area. The Department has not modeled a total destruction scenario in Tier 2 and Tier 3 areas of its service territory because such areas represent a small portion of the Power System's service territory; but the Department believes that based on the low density of the property in the applicable Tier 2 and Tier 3 areas, the potential property damage is expected to be relatively low. In these applicable Tier 2 and Tier 3 areas, the Department continues to replace wooden pole assets with alternative material poles, install covered conductors where feasible, equip poles for high wind load in order to resist fire damage, and employ a robust vegetation management program to further mitigate wildfire risk exposure.

AB 1054 was signed into law by Governor Newsom in July 2019. AB 1054 requires POUs to submit their wildfire mitigation plans for annual review to a newly created California Wildfire Safety Advisory Board (the "CWSAB"), with comprehensive revisions submitted every three years. The Department continues to submit its wildfire mitigation plan to the CWSAB on an annual basis, with the last submittal occurring on June 28, 2023. The Department's 2023 wildfire mitigation plan represents a comprehensive update, meeting the requirements of AB 1054. On December 4, 2023, the CWSAB published its guidance advisory opinion for the recently submitted wildfire mitigation plans. The CWSAB's advisory opinion to each POU was to embark on a collaborative approach as set forth in the advisory opinion designed to improve POU reporting on its wildfire prevention efforts and the CWSAB's ability to comprehend and advise on those reports. Previous reviews by the CWSAB found the Department's wildfire mitigation plan to be comprehensive with clear descriptions of its relevant programs. The Department is actively engaging with the ongoing CWSAB's meetings to discuss updates to POU wildfire mitigation plans. The Department is required to submit its next annual update to the Department's wildfire mitigation plan to the CWSAB by July 1, 2024.

AB 1054 also establishes a new wildfire fund for IOUs to pay for eligible, uninsured third-party damage claims arising from future covered wildfires. Participation in the wildfire fund is exclusive to IOUs. Each of the major IOUS in California are now participating in the Wildfire Fund. POUs, such as the Department, are not eligible to participate in or receive funding for wildfire claims from the Wildfire Fund

A number of wildfires occurred in the State in the last several years. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by such utilities' infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County*, No. S243247 (Cal. Aug. 15, 2019) involving damages related to sewage overflows from a city sewer system, the California Supreme Court issued a rare but narrow decision regarding inverse condemnation liability. The residential property owner in that case failed to install a mandatory sewer backflow device, allowing the court to conclude the absence of that device was the substantial cause of the damages to the residence. The property owner was unable to prove the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. SB 1028, SB 901 and AB 1054 do not address existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions address the State's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry, including the Department.

See "LITIGATION – Wildfire Litigation" for information about current litigation regarding wildfires and "THE DEPARTMENT – Insurance" for information about the Department's current insurance coverage for wildfires.

Environmental Regulation and Permitting Factors

General. Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions. The Department's four Los Angeles Basin power plants are subject to the Regional Clean Air Incentives Market ("RECLAIM") NOx regulations adopted by the SCAQMD. In accordance with these regulations, SCAQMD established annual NOx allocations for stationary source facilities based on historical emissions with a declining emissions cap. These allocations are in the form of RECLAIM trading credits ("RTCs"). Facilities can comply with RECLAIM by purchasing RTCs from the RECLAIM market, installing emission controls, and/or reducing operations. The Department has installed emission control equipment at its power plants to reduce NOx emissions. The Los Angeles Basin Stations are all equipped with emission control equipment. As a result of the installation of NOx control equipment and the modernization of existing electric generating units, the Department has had sufficient RTCs to meet its native load requirements for normal operations under the NOx RECLAIM regulation.

In March 2017, the SCAQMD adopted the 2016 Air Quality Management Plan and included a control measure to achieve an additional five tons per day NOx reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology ("BARCT") as soon as feasible.

In July 2017, AB 617 was signed into law, which addresses criteria pollutants (including NOx) and toxic air contaminants at stationary sources. RECLAIM facilities are subject to the BARCT requirements of AB 617.

The market-based RECLAIM program is being transitioned to a command-and-control regulatory structure. The RECLAIM program was originally scheduled to end on December 31, 2023 but is now expected to extend past 2025 after the EPA's approval of the State Implementation Plan and the resolution of outstanding issues with the New Source Review ("NSR") Program. The Los Angeles Basin Stations will transition from RECLAIM to a source-specific NOx rule for electric generating units that will include NOx limits reflecting BARCT. SCAQMD Rule 1135, the "command-and-control" rule for electric generating units, was adopted in November 2018. Instead of receiving an annual allocation of emission credits, electric generating units will be required to meet a NOx emission limit. The NOx emission limit for simple cycle gas turbines is 2.5 parts per million ("ppm") while the NOx emission limit for combined cycle gas turbines is 2.0 ppm. Failure to meet the NOx limits by the December 31, 2023 compliance date would prohibit out-of-compliance generating units from operating. To comply with the new NOx limit of 2.5 ppm for simple cycle gas turbines, the existing selective catalytic reduction equipment for the Department's simple cycle combustion turbines at the Harbor Generating Station and the Valley Generating Station were tuned. To meet the 2.0 ppm limit for combined cycle gas turbines, the combustors of combined cycle combustion turbines at the Harbor Generating Station are being upgraded. The upgrade of the Harbor Generating Station's combined cycle combustors is still in progress. The Harbor Generating Station's combined cycle unit is currently offline and is expected to be in compliance with the Rule 1135 NOx emission limit upon returning to service. The Department does not expect the modifications to have a material adverse effect on the operations or financial condition of the Power System. The remaining electric generating units at the Los Angeles Basin Stations either already meet the NOx limits or are exempt from the rule. On January 7, 2022, Rule 1135 was amended to reference startup and shutdown provisions as defined in SCAQMD Rule 429.2, which establishes requirements during startup and shutdown and exempts units regulated under Rule 1135 from NOx emission limits during startup and shutdown.

Regulatory Actions Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates GHG emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, GHGs are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies to control emissions from the new or modified stationary source. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. GHGs from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

In May 2023, the EPA proposed new carbon pollution standards for coal and natural gas-fired power plants. The proposed rule would establish CO_2 emissions limits and guidelines for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines. The proposal includes the following elements, in each case reflecting the application of best systems for emissions reduction ("BSER"), taking into account costs, energy requirements and other statutory factors: (i) strengthening the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establishing emission guidelines for carbon pollution from existing fossil fuel-fired steam generating units (including coal, oil and natural gas-fired units) beginning January 1, 2030; and (iii) establishing emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired) beginning January 1, 2032 or January 1, 2035, depending on which BSER technology is pursued. Under the proposed rule, emissions standards are established for different subcategories of power plants according to unit characteristics such as their capacity, their intended length of operation, and/or their frequency of operation. The proposed rule would generally require more CO_2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO_2 requirements over time. The standards are based on emission control methods that can be installed at the plants, including technologies such as carbon capture and sequestration/storage, low-GHG hydrogen co-firing, and natural gas co-firing; however, the determination of whether to implement such technologies or to comply with the proposed emissions limits by other means would be made by power plant operators and state regulators. Under the proposal, states would be required to submit compliance plans to the EPA within 24 months of the effective date of the adoption of the regulations. The EPA requested public comment on the proposed regulation. The Department submitted comments and will continue to participate in the rulemaking process. There can be no assurance that the final regulations to be adopted after public comment will reflect the currently proposed standards or as to the timing of the adoption and implementation thereof.

See also "THE POWER SYSTEM – General," "– Department-Owned Generating Units," "– Jointly Owned Generating Units and Contracted Capacity Rights in Generating Units," "– Projected Capital Improvements," "– Energy Efficiency" and "– Renewable Power Initiatives."

Air Quality – Mercury. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants ("HAPs"), including mercury. In February 2012, the EPA finalized a rule called the Mercury and Air Toxics Standards ("MATS") to reduce emissions of toxic air pollutants, including mercury, from coal- and oil-fired electric generating units, and subsequently amended the rule in 2013 and 2014. The MATS rule set technology-based emission limitation standards for mercury and other toxic air pollutants, based upon reductions available through the use of "maximum achievable control technology" at coal- and oil-fired electric generating units. The rule has minimal impact to IPP, the one remaining coal-fired plant that is a source of energy for the Department. IPP did not have to install control technology and EPA has deemed the IPP units as low-emitting electric generating units ("LEEs"). IPP is subject to periodic testing, work practice standards and recordkeeping requirements.

The State of Utah adopted minimum performance criteria for existing electric generating units and offset requirements for potential increases in mercury emissions from new or modified electric generating units. Utah's minimum performance criteria include a rule, effective January 1, 2012, that coal-fired power plants, such as IPP, meet a mercury emissions limit of 0.00000065 lb/MMBtu or have at least a 90% mercury removal efficiency. IPP complies with the Utah mercury standard.

In April 2023, the EPA published its proposed rule entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review." The proposed rule establishes a lower mercury emissions standard for lignite coal, which does not apply to IPP. The rule also proposes to reduce the emissions standard for filterable particulate matter ("fPM") from 0.03 lb/MMBtu to 0.01 lb/MMBtu. In addition, it requires the owners and operators of existing coal-fired plants to only use a continuous emissions monitoring system ("CEMS") to demonstrate compliance with the new fPM standards. The EPA requested comments on the proposed rule, as well as on the possibility of reducing the compliance timeframe from three years to one year from the effective date. IPP submitted a comment letter. The final rule is expected to be published in Spring 2024. *{update to come}*

SCAQMD Air Quality Management Plan. The SCAQMD periodically prepares an overall plan, known as an Air Quality Management Plan (the "AQMP"), which include control measures to meet federal air quality standards and incorporate the latest technical planning information. The AQMP is a regional and multi-agency effort. In 2021, the Department participated in the stakeholder working group meetings dedicated to the development of the 2022 AQMP and the rules and rule amendments to implement the control measures included in the 2022 AQMP that could potentially impact the Department's operations. In December 2, 2022, the SCAQMD Board approved the 2022 AQMP, which aims for a 45% reduction in NOx emissions through this plan. In January 2023, CARB adopted the SCAQMD 2022 AQMP, and directed staff to submit the 2022 AQMP to the EPA as a revision to the California State Implementation Plan to achieve the federal air quality standard for ozone. As called for in the 2022 AQMP, SCAQMD has initiated separate rulemaking processes addressing the different proposed control measures cited in the AQMP, which are ongoing.

Water Quality – Cooling Water Process.

General. A cooling process is necessary for nearly every type of steam turbine electrical generating station. Once-through-cooling is the process where water is drawn from a source, pumped through equipment at a power plant to provide cooling and then discharged. In once-through-cooling, the water is not chemically changed in the cooling process; however, the water temperature can increase. The water drawn into the intake and the thermal discharges are regulated by the federal Clean Water Act and similar state law.

EPA Requirements. A final regulation implementing Section 316(b) of the Clean Water Act ("Rule 316(b)") addresses the impacts of water intake by once-through-cooling systems. Rule 316(b) affects intake structures for power generating facilities that withdraw more than two million gallons per day for cooling purposes. The Department has determined it will comply with impingement mortality ("IM") and entrainment mortality ("EM") by replacing once-through-cooling with other technology by the deadline of 2029 negotiated with the SWRCB.

State Water Resources Control Board. The SWRCB established a separate statewide policy with respect to the Clean Water Act Section 316(b) in 2010 published as Section 2922 of Title 23 of the California Code of Regulations ("Regulation Section 2922"). The regulation generally requires all facilities subject to the Clean Water Act Section 316(b) to either use closed cycle cooling or flow reduction commensurate to that of wet closed cycle. The Department owns three coastal generating stations that utilize once-through-cooling, that provide approximately 85% of the Department's in-basin generation and 39% of the total generating plant capacity owned by the Department, which are subject to Regulation Section 2922.

In July 2011, the SWRCB adopted an amendment to Regulation Section 2922 that accelerated the compliance dates for three coastal units and extended the compliance dates until 2024 for two coastal units and 2029 for the remaining four coastal units. In August 2023, the SWRCB adopted another amendment, extending the compliance date for the two units with a December 31, 2024 deadline to December 31, 2029. The new compliance schedule allows for both grid reliability and a financially sustainable path forward while making the equipment upgrades necessary to remove the coastal generating stations' units from utilizing once-through-cooling, shifting the focus from repowering to clean energy alternatives.

Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station. The SWRCB's Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bay and Estuaries of California (the "California Thermal Plan") has different thermal criteria for discharges into estuaries and bays than it does for discharges into the ocean. The water discharges from Harbor Generating Station and Haynes Generating Station were originally permitted as ocean discharges. In January 2003, however, the Los Angeles Regional Water Quality Control Board ("LARWQCB") informed the Department that it (i) reclassified the Harbor Generating Station discharge as an enclosed bay discharge and that (ii) it intends to reclassify the Haynes Generating Station discharge as an estuary discharge during the next permit renewal. The Harbor Generating Station NPDES permit was renewed by the LARWQCB in July 2003, with the new enclosed bay classification and the associated, more stringent, permit limits. Based on the notice of intent to reclassify the Haynes Generating Station discharge and planned changes to be made to the Haynes Generating Station's flow volume, the Department has completed a hydrological model of the Lower San Gabriel River. Haynes discharges into the San Gabriel River, which in turn flows into the ocean. The hydrological study concluded that the estuary classification does not reflect current site conditions with the operation of the existing power plants. However, the LARWQCB stated that for regulatory purposes, the Lower San Gabriel River would likely represent an estuary. With this designation, the Haynes Generating Station would be unable to comply with the California Thermal Plan and other permit conditions without a permit variance. If the Department is unable to obtain a permit variance, the Haynes Generating Station facility could be limited or unable to operate. The LARWQCB has recognized the need to continue utilizing once-through cooling at the Haynes Generating Station through 2029 for electric grid reliability and is currently working with the Department on a solution for all discharge issues associated with the estuary designation, which could include the issuance of a variance or time schedule order (TSO).

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, as well as State statutes, impose strict liability for cleanup costs upon those who generate or dispose of hazardous substances and hazardous wastes. The Department's past disposal practices may result in Superfund liability as previously approved disposal methods or sites become candidates for Superfund classification. In addition, under these statutes, the Department may be held liable for cleanup activities on property that it owns and operates, even if the conditions requiring cleanup existed before the Department's occupancy of a site. As a result, the Department may incur substantial, but presently unknown, costs as a participant in the cleanup of sites contaminated with hazardous substances or wastes.

Coal Combustion Residuals. In April 2015, the EPA promulgated the final coal combustion residuals ("CCR") rule, which regulates the disposal and management of CCRs as non-hazardous under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The final CCR rule became effective in October 2015.

Under the CCR rule, existing impoundments for managing CCR must either cease accepting CCR materials as of the rule's effective date, or implement a variety of measures to ensure that such facilities will not result in releases to the environment. One such requirement is that all such facilities be retrofitted with liners that are intended to prevent the migration to groundwater of contaminants found in CCR. In addition, the rule requires monitoring of groundwater to determine whether releases have occurred, and to contain or clean up any such releases that are discovered.

The IPP utilizes impoundments (ponds and landfills) for the management of CCR that are subject to the CCR rule. The IPP has met all interim compliance requirements for the new CCR rule including: setting up a public website and posting CCR operating records, developing new groundwater monitoring wells and sampling plans, beginning to sample groundwater wells quarterly, and developing and implementing a fugitive dust monitoring plan.

The Department believes that the IPP's CCR management facilities may not meet the design criteria required for surface impoundments and that releases of certain contaminants have occurred from the current, unlined impoundments. The Department understands that IPA has made notification that IPP will cease operations of the coal-fired boilers and switch to another fuel source for generation by 2028.

The Department has estimated the IPP's total cost of compliance with the final CCR rule to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period commencing in 2019 and ending between approximately 2025 and 2028 (except for long-term monitoring and maintenance, which would last approximately 30 years after closure). Of this total cost, the Power System would be responsible for a percentage equal to its total use of energy produced by IPP. For more information about IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

In November 2019, the EPA proposed revisions (Part A) to the CCR rule. The proposed revisions focus on closure requirements for impoundments and landfills. IPA is opting to comply with the alternate closure requirement as currently described in the current CCR rule. The proposed revisions include additional requirements to get approval of the EPA or the state to close impoundments in accordance with alternate closure procedures. There is also a new requirement to prepare a plan to mitigate potential risk to human health and environmental from CCR surface impoundments. The Part A revisions were finalized and published in the Federal Register in August 2020. IPP has submitted a request to the EPA demonstrating that they meet the alternate closure procedures as described in the regulations. IPP is awaiting EPA review and approval which was initially expected to be received by April 2021; [however, as of ______ 2024, the EPA has not yet made a determination on IPP's demonstration submission]. *{update to come}*

In February 2020, the EPA proposed a federal CCR permit program. Currently, the CCR rule is self-implementing and is enforced primarily though citizen suits which are decided in federal district courts. This program will not change the provisions of the regulations but the EPA will be able to review, approve, issue, and enforce the CCR regulations through the permit program.

In March 2020, the EPA proposed more revisions (Part B) to the CCR rule including provisions to demonstrate equivalent alternate liners, using CCR for closing impoundments, and completion of closure by removal during post closure care period. The proposed revisions do not impact IPA's plan to follow alternate closure requirements.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects resulting from exposure to electric and magnetic fields created by high voltage transmission and distribution equipment. Additional studies are being conducted to determine the relationship between electric and magnetic fields and certain adverse health effects, if any. At this time, it is not possible to predict the extent of the costs and other impacts, if any, which the electric and magnetic fields concerns may have on electric utilities, including the Department.

For additional information regarding environmental matters, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Hoover Power Plant – Environmental Considerations" and " – Palo Verde Nuclear Generating Station – Nuclear Waste Storage and Disposal.*"

Energy Regulatory Factors

Developments in the California Energy Market. In the late 1990s, the State restructured its electricity market so that regulated retail suppliers were required to purchase their customers' supply needs through a centralized, wholesale market. During portions of 2000 and 2001, wholesale market prices in the State became highly volatile. The volatility in wholesale prices that the State experienced in 2000 and 2001 was due to a number of factors, including flaws in the structure of the wholesale market and unlawful manipulation of the wholesale market. As discussed below, the wholesale market in the State has since been redesigned, and Congress has established mechanics for policing wholesale markets.

Volatility in electricity prices in the State may nevertheless return due to a variety of factors that affect the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of GHG emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impact of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in the State and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). Volatility in electricity prices may contribute to greater volatility in the Power System's Power Revenue Fund from the sale (and purchase) of electric energy and, therefore, could materially affect the financial condition of the Power System. To mitigate price volatility and the Department's exposure on the spot market, the Department undertakes resource planning activities and plans for its resource needs. Of particular note, the Department has power supply contracts and other arrangements relating to its system supply of power that are of specified durations. See "THE POWER SYSTEM – Generation and Power Supply."

Energy Policy Act of 1992. The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in federal regulation of the electric utility industry, particularly in the area of transmission access under sections 211, 212 and 213 of the Federal Power Act, 16 U.S.C. § 791a et seq. The purpose of these changes, in part, was to bring about increased competition among wholesale suppliers. As amended, sections 211, 212 and 213 authorize FERC to compel a transmission provider to provide transmission service upon application by an electricity supplier. FERC's authority includes the authority to compel the enlargement of transmission capacity as necessary to provide the service. The service must be provided at rates, charges, terms and conditions that are set by FERC. Electric utilities that are owned by municipalities or other public agencies are "transmitting utilities" that may be subject to an order under sections 211, 212 and 213. EPAct 1992 prohibits FERC from requiring "retail wheeling" under which a retail customer that was located in one utility's service area could obtain electricity from another source. An order by FERC to provide transmission might adversely affect the Power System by, and among other things, increasing the Department's cost of owning and operating transmission facilities and/or by reducing the availability of the Department's transmission resources for the Department's own use.

Energy Policy Act of 2005. The Energy Policy Act of 2005 ("EPAct 2005") addresses a wide array of matters that affect the entire electric utility industry, including the Department.

Subject to certain conditions and limitations, EPAct 2005 authorizes FERC to require an unregulated transmitting utility such as the Department to provide electric transmission services at rates that are comparable to those that the unregulated transmitting utility charges itself; and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. FERC may compel open access in this context unless the order would violate a private activity bond rule for purposes of section 141 of the Code (as defined below). To date, FERC has chosen to exercise its authority on a case-by-case approach. Additionally, FERC has the authority to require the provision of transmission services in response to specific requests for service. See ELECTRIC RATES – Rate Regulation. Furthermore, should the Department purchase transmission services from a public utility, as defined in the Federal Power Act, pursuant to the terms and conditions of FERC's *pro forma* OATT, the *pro forma* OATT requires the Department to provide the transmission provider it is purchasing transmission services from, comparable transmission service that it is capable of providing on similar terms and conditions over facilities and for the transmission of electric energy.

EPAct 2005 provides for criminal penalties for manipulative energy trading practices.

EPAct 2005 repealed the Public Utility Holding Company Act of 1935, which prohibited certain mergers and consolidations involving electric utilities. EPAct 2005 gives FERC and state regulators access to books and records within holding companies that include regulated public utilities. In addition, FERC may oversee inter-affiliate transactions within such holding company systems. These provisions of EPAct 2005 are referred to as "PUHCA 2005." PUHCA 2005 does not apply to the Department but generally accommodates more combinations of assets within the electric utility industry.

EPAct 2005 requires the creation of national and regional electric reliability organizations to establish and enforce, under FERC's supervision, mandatory standards for the reliable operation of the bulk power system. The standards are designed to increase system reliability and to minimize blackouts. FERC has designated NERC as the national electric reliability organization. FERC has designated WECC as the regional reliability organization for utilities in the West, including the Department. Failure to comply with NERC and WECC standards exposes a utility such as the Department to penalties. NERC and WECC audit the Department's compliance with the reliability standards once every three years and, as indicated above, impose penalties for non-compliance. The Department has from time to time fallen short in meeting its regulatory and reporting requirements on a timely basis and either has self-reported or responded to audit findings from WECC. The Department does not believe that pending reporting and audit matters will have a material adverse effect on the Department's operations or financial position.

Under EPAct 2005, State IOUs were required to offer, to each of their classes of customers, a time-based rate schedule that would enable customers to manage their energy use through advanced metering and communications technology.

EPAct 2005 authorizes FERC to compel the siting of certain transmission lines if FERC determines that a state has unreasonably withheld approval.

EPAct 2005 promotes increased imports of liquefied natural gas and includes incentives to support the development of renewable energy technologies. EPAct 2005 also extends for 20 years the Price-Anderson Act, which provides certain protection from liability for nuclear power issues and provides incentives for the construction of new nuclear plants.

Future Regulation of the Electric Utility Industry. The electric utility industry is highly regulated and is also regularly subject to reform. The most recent reforms and proposals are aimed at reducing emissions of GHGs from combustion of fossil fuels and reducing impacts from using ocean water for power plant cooling. The Department is unable to predict future reforms to the electric utility industry or the ultimate impact on the Department of recent reforms and proposals. In particular, the Department is unable to predict the outcome of proposals on reducing GHG emissions and the associated impact on the operations and finances of the Power System or the electric utility industry.

Security of the Power System

The Department has a variety of physical security measures in place, as well as a cybersecurity program, aimed at protecting the assets of the Power System and the technological systems utilized in the delivery of electric power service to its customers. The Department operates a 24/7 operations center and regularly plans for emergency situations and develops response protocols.

Elements of the Department's cybersecurity program include ongoing monitoring, regular staff training and a robust defense-in-depth strategy, as well as other cybersecurity and operational safeguards such as performance of periodic security risk assessments and gap analyses to identify security strengths and vulnerabilities; practices for the backup and recovery of data; security awareness training, and response plans.

The Department also collaborates with federal and state partners and other public and private third parties to assess vulnerabilities, share information and actively detect and manage risks. However, there can be no assurance that any existing or additional safety and security measures will prove adequate in the event that cyberattacks or military conflicts or terrorist activities (including cyber terrorism) are directed against the Power System.

Attacks, especially zero-day exploits directed at critical electric sector operations could damage generation, transmission or distribution assets, cause operational malfunctions and outages, and result in costly recovery and remediation efforts. Further, cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period. United States government agencies have in the past issued warnings indicating that critical infrastructure sectors such as the electric grid may be specific targets of cybersecurity threats. The costs of security measures or of remedying physical and/or cybersecurity breaches could be material.

Global Health Emergencies; COVID-19 Pandemic

A pandemic, epidemic or outbreak of an infectious disease can have significant adverse health and financial impacts on global and local economies. For example, beginning in 2020, the COVID-19 pandemic negatively affected economic activity throughout the world, including the United States and the State of California. The initial impacts of stay-at home orders globally was unprecedented, with commerce, travel, asset values and financial markets experiencing disruptions worldwide. The COVID-19 pandemic impacted the Department in certain respects, however, there was not a material adverse impact to the Power System's operations or its ability to meet its financial obligations as a result of the COVID-19 pandemic. Certain employees of electric and water utility systems, like the Department, are considered essential workers and were exempt from the "stay at home" and "safer at home" orders issued by the State, the County and the City, and therefore, the Department continued to fully provide power and water services to its customers throughout the pandemic. In response to the COVID-19 outbreak, the Department implemented a number of temporary measures intended to mitigate operational and financial impacts to the Department, and to assist the Department's customers. In light of the measures taken by the Department to mitigate the economic impact of COVID-19 on its customers, including extended payment options and deferrals of disconnections of water and power services for non-payment, the Department has experienced and may continue to experience an increase in delinquent accounts and increase of uncollectible accounts. See "ELECTRIC RATES – Billings and Collections – *COVID-19 Effects*."

The declarations of the COVID-19 pandemic as a public health emergency have been lifted. However, future pandemics and other widespread public health emergencies can and do arise from time to time. No assurance can be given that the operations or finances of the Power System will not be negatively affected in the event that the pandemic and its consequences again become more severe or another national or localized outbreak of highly contagious or epidemic disease occurs in the future.

Changing Laws and Requirements

On both the state and federal levels, legislation is introduced frequently that would have the effect of further regulating environmental impacts relating to energy, including the generation of energy using conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cyber-security legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, and renewable energy incentives that could provide grants and credits to municipal utilities to invest in renewable energy infrastructure. Congress has also considered other bills relating to energy supplies and development.

The Department is unable to predict at this time whether any of these or other legislative proposals will be enacted into law and, if so, the impact they may have on the operations and finances of the Power System or on the electric utility industry in general.

In addition to state and federal legislation, citizen initiatives in the State can lead and have led to substantial restrictions upon governmental agencies, both in terms of raising revenue and management of governmental entities generally. Articles XIII C and XIII D of the State's constitution provided limits on the ability of governmental agencies to increase certain fees and charges. Such articles were adopted pursuant to measures qualified for the ballot pursuant to the State's constitutional initiative process.

In addition, from time to time other initiative measures could be adopted by State voters, which may place limitations on the ability of the Department to increase revenues.

See also "ELECTRIC RATES – Rate Setting – *Proposition 26*."

Other General Factors

The electric utility industry in general has been, or in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of many electric utilities, including the Department, and the level of utilization of generation and transmission facilities. Such factors (a number of which are further discussed elsewhere herein), include, among others:

- Effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements;

- Changes resulting from conservation and demand side management programs on the timing and use of energy;

- Effects on the integration and reliability of the power supply from the increased usage of renewables;

- Changes resulting from a national energy policy;

- Effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities and from competitive transmitting of less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity;

- The repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities;

- Increased competition from independent power producers and marketers, brokers and federal power marketing agencies;

- "Self-generation" or "distributed generation" (such as microturbines, fuel cells, and solar installations) by industrial and commercial customers and others;

- Issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission line service from transmission projects financed with outstanding tax-exempt obligations;

- Effects of inflation on the operating and maintenance costs of an electric utility and its facilities;

- Changes from projected future load requirements;

- Increases in costs and uncertain availability of capital;

- Shifts in the availability and relative costs of different fuels (including the cost of natural gas and coal);

- Financial difficulties, including bankruptcy, of fuel suppliers and/or renewable energy suppliers;

- Changes in the electric market structure for neighboring electric grids such as the EIM operated by the Cal ISO;

- Sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the State;

- Inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity;

- Other legislative changes, voter initiatives, referenda and statewide propositions;

- Effects of changes in the economy, population and demand of customers in the Department's service area;

- Effects of possible manipulation of the electric markets;

- Acts of terrorism or cyberterrorism;

- Impacts of climate change;

- The outbreak of another infectious disease such as the COVID-19 pandemic impacting the global, national or local economy or a utility's service area;

- Natural disasters or other physical calamities, including but not limited to, earthquakes, floods and wildfires, and potential liabilities of electric utilities in connection therewith;

- Adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk; and

- Legislation or court actions allowing City residents and/or businesses to purchase power from sources outside the Department.

Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility, including the Department.

Seismic Activity

The City and the Owens River and Mono Basin areas are located in regions of seismic activity. The principal earthquake fault in the Los Angeles area is the San Andreas Fault, which extends an estimated 700 miles from north of the San Francisco area to the Salton Sea. At its nearest point to the City, the San Andreas Fault is about 35 miles north of the Los Angeles Civic Center.

In March 2015, the Uniform California Earthquake Rupture Forecast (the "2015 Earthquake Forecast") was issued by the Working Group on California Earthquake Probabilities. Organizations sponsoring the Working Group on California Earthquake Probabilities include the U.S. Geological Survey, the California Geological Survey, the Southern California Earthquake Center and the California Earthquake Authority. According to the 2015 Earthquake Forecast, the probability of a magnitude 6.7 or larger earthquake over the next 30 years (from 2014) striking the greater Los Angeles area is 60%. From the Uniform California Earthquake Rupture Forecast published in April 2008 (the "2008 Earthquake Forecast"), the estimated rate of earthquakes around magnitude 6.7 or larger decreased by about 30%. However, the estimate for the likelihood that the State will experience a magnitude 8.0 or larger earthquake in the next 30 years (from 2014) increased from about 4.7% in the 2008 Earthquake Forecast to about 7.0% in the 2015 Earthquake Forecast. The 2015 Earthquake Forecast considered more than 250,000 different fault-based earthquakes, including multi-fault ruptures, whereas the 2008 Earthquake Forecast considered approximately 10,000 different fault-based earthquakes.

While it is impossible to accurately predict the cost or effect of a major earthquake on the Power System or to predict the effect of such an earthquake on the Department's ability to provide continued uninterrupted service to all parts of the Department's service area, there have been various studies conducted to assist the Department in assessing seismic risks. Based on these studies, the Department completed numerous projects designed to mitigate seismic risks and seismically strengthen Power System infrastructure and facilities. Projects include landslide repairs and bank replacements, the placement of spare transformers and the installation of generating peaking units at the Valley Generating Station and Haynes Generating Station to provide peaking capacity and the ability for generating units to go from a shutdown condition to an operating condition and start delivering power without assistance from the power grid. No studies have been conducted or commissioned by the Department outside of the State. See "GENERAL – Insurance."

LITIGATION

General

A number of claims and suits are pending against the Department or that directly affect the Department with respect to the Power System for alleged damages to persons and property and for other alleged liabilities arising out of its operations. Certain of these suits are described below. In the opinion of the Department, any ultimate liability which may arise from any of the pending claims and suits is not expected to materially impact the Power System's financial position, results of operations, or cash flows.

Wildfire Litigation

In recent years, there has been an increase in the number and the severity of wildfires in the State. Due to this increase of fire activity, there has been an increase in litigation filed against power utilities that own and operate generating stations, distribution lines, and transmission lines throughout the State. The Department is a named party in cases relating to the Creek fire, which ignited on December 5, 2017, and the Getty fire, which ignited on October 28, 2019. The Department denies liability for the ignition of the Creek fire. The unique set of facts regarding the ignition of the Getty fire likely creates Department liability; however, various defense theories and third party claims are being explored.

Creek Fire. Regarding the Creek fire, the Department has a number of cases pending in the Los Angeles Superior Court. The state court cases are brought by attorneys representing individual plaintiffs for alleged property damage and business losses. The cases have all been consolidated for litigation with a single judge. Edison is also a party in the state court cases, and is a focus of the fire ignition. Edison was named as a co-defendant by the individual plaintiff and insurance subrogation plaintiffs. Edison has filed an indemnity cross-complaint against the Department. All equitable allegations/comparative fault allegations would be part of the state court trial. On September 15, 2023, as a result of the court's ruling on a joint motion by the Department and Edison to dismiss certain plaintiff cases, approximately 370 individual plaintiff cases were dismissed, leaving approximately 90 individual plaintiff cases. The dismissals significantly reduce the Department's financial exposure for the wildfire.

If liability is found against the Department in connection with the Creek fire, an accurate exposure amount cannot now be estimated. However, the cumulative alleged damages in the pending state court cases, which now include only individual plaintiff cases and a reduced number of plaintiffs, is within the Department's insurance coverage for this matter. The Department has insurance coverage for this matter in the amount of $185 million with a $3 million self-insured retention.

Getty Fire. The Power System matters associated with the Getty fire currently involve multiple cases all alleging inverse condemnation and tort causes of action. The state court actions were filed on behalf of individual plaintiffs and insurance subrogation parties. The cases are pending in the Los Angeles Superior Court Complex Division with all cases ordered consolidated/related before a single judge.

Cross-complaints have been filed by the Department naming the adjacent property owner C&C Mountaingate, Inc., and Department tree vegetation contractor Utility Tree Service, LLC and its subcontractor, Tree Service Kings, Inc.

The court has set a September 18, 2024, trial date regarding only the inverse condemnation issue. At that time the court will determine if inverse condemnation applies, and if so, a later date will be set at which a jury will decide the amount of damages.

On or about October 16, 2023, the insurance subrogation plaintiffs and the Department reached a settlement of the insurance subrogation plaintiffs' claims for $36,786,657.50. The individual plaintiff cases remain.

The total financial exposure of the Getty fire cannot now be specifically determined. However, the cumulative damages presently alleged in the pending state court cases, which now include only individual plaintiff cases, is within the Department's insurance coverage for this matter. The Department has insurance coverage in the amount of $177.5 million with a $3 million self-insured retention for this matter. Despite not having done anything wrong, the Department could face financial liability claims due to the doctrine of inverse condemnation discussed above under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – Legislation and Court Action Relating to Wildfires."

For details regarding the extent of the Department's current insurance, see "GENERAL – Insurance." As discussed under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*," legislation addressing the State's inverse condemnation and "strict liability" issues for utilities in the context of wildfires in particular could have a significant effect on the electric utility industry, including the Department.

APPENDIX B
INTERMOUNTAIN POWER AGENCY AND THE INTERMOUNTAIN POWER PROJECT

INTRODUCTION

Intermountain Power Agency

Intermountain Power Agency (the "Agency") was organized in June 1977 by several Utah municipalities under the Utah Interlocal Cooperation Act, Title 11, Chapter 13, Utah Code Annotated 1953, as amended (the "Act"), and pursuant to the Intermountain Power Agency Organization Agreement, dated May 10, 1977 (as amended, the "Intermountain Power Agency Organization Agreement"). See "INTERMOUNTAIN POWER AGENCY" in that certain Annual Disclosure Report, dated March 29, 2024, filed by the Agency with the Municipal Securities Rulemaking Board through its Electronic Municipal Market Access system ("EMMA") (such Annual Disclosure Report being the "Agency ADR"). This Appendix does not purport to cover all aspects of the Agency or the Intermountain Power Project ("IPP"). A copy of the most recent official statement for the issuance of the Agency's securities and the Agency's continuing disclosure filings, including the Agency ADR, may be obtained from EMMA. For information regarding risks associated with and recent developments relating to the Agency's securities and IPP, see "RISK FACTORS," "ELECTRIC INDUSTRY RESTRUCTURING" and "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" in the Agency ADR. Each term used but not otherwise defined in this Appendix has the meaning ascribed to such term in the Agency ADR.

The IPP Purchasers and Renewal IPP Purchasers

Power Sales Contracts. The Agency has sold the entire capability of IPP through June 15, 2027 to 35 entities (the "IPP Purchasers") on a "take-or-pay" basis pursuant to separate power sales contracts between the Agency and each IPP Purchaser (which power sales contracts, as amended, are referred to herein as the "Power Sales Contracts"). The IPP Purchasers are 35 utilities consisting of the Department of Water and Power of The City of Los Angeles (the "Department") and the California cities of Anaheim, Riverside, Burbank, Glendale and Pasadena (together with the Department, collectively, the "Original California Purchasers"); the 23 members of the Agency (collectively, the "Utah Municipal Purchasers"); and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming (collectively, the "Cooperative Purchasers" and, together with the Utah Municipal Purchasers, collectively, the "Utah Purchasers"). The Original California Purchasers, the Utah Municipal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Power Sales Contracts, to purchase 78.943%, 14.040% and 7.017%, respectively, of the net capability of the Generation Station. For information regarding the respective rights, duties and obligations of the IPP Purchasers under the Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Power Sales Contracts" in the Agency ADR.

Renewal Power Sales Contracts. The Agency has sold the entire capability of IPP for the period beginning on June 16, 2027 (the "Transition Date") and ending on June 15, 2077 to 30 entities (the "Renewal IPP Purchasers") on a "take-or-pay" basis pursuant to separate renewal power sales contracts between the Agency and each Renewal IPP Purchaser (which renewal power sales contracts, as amended, are referred to herein as the "Renewal Power Sales Contracts"). The Renewal IPP Purchasers are 30 utilities consisting of the Department and the California cities of Burbank and Glendale (collectively, the "California Renewal Purchasers"); the 21 entities that will remain as members of the Agency from and after June 16, 2027 (collectively, the "Utah Municipal Renewal Purchasers"); and the six Cooperative Purchasers (together with the Utah Municipal Renewal Purchasers, collectively, the "Utah Renewal Purchasers"). The

California Renewal Purchasers, the Utah Municipal Renewal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Renewal Power Sales Contracts, to purchase 78.943%, 13.975% and 7.082%, respectively, of the net capability of the Generation Station. For information regarding the respective rights, duties and obligations of the Renewal IPP Purchasers under the Renewal Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Renewal Power Sales Contracts" in the Agency ADR.

Excess Power Sales Agreement. Pursuant to the Excess Power Sales Agreement referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Excess Power Sales Agreement" in the Agency ADR (as amended, the "Excess Power Sales Agreement"), through June 15, 2027, the Utah Purchasers have sold to the Department and the California cities of Pasadena, Burbank and Glendale (collectively, the "Excess IPP Purchasers") their entitlements to the use of the capability of IPP except for any portion of any such entitlement that a Utah Purchaser has, from time to time, recalled under the Excess Power Sales Agreement. So long as no such recall is in effect, the Original California Purchasers are committed to take or pay for 100% of the capability of the Generation Station, *provided, however*, the Utah Purchasers remain, and will remain, primarily obligated to the Agency under their respective Power Sales Contracts to pay for IPP capability they have sold to the Excess IPP Purchasers, but are discharged from such obligation to the extent the Excess IPP Purchasers make payments to the Agency on their behalves pursuant to the Excess Power Sales Agreement. However, to the extent set forth in the table below entitled "Percentages of Capability of Generation Station to be Purchased," certain of the Utah Purchasers have recalled portions of their entitlements to the use of the capability of IPP. While such recall, or any recall that the Utah Purchasers may elect to make hereafter, is in effect, the percentage of the capability of the Generation Station that the Excess IPP Purchasers will be committed to take or pay for shall be reduced by the percentage of capability of the Generation Station that has been recalled, and each recalling Utah Purchaser will be the only IPP Purchaser committed to take or pay for the percentage of capability so recalled by such IPP Purchaser. The Utah Purchasers may, subject to the lead times and other requirements of the Excess Power Sales Agreement, recall from the Excess IPP Purchasers all or any portion of the Utah Purchasers' aggregate 21.057% entitlements to the use of the capability of IPP.

Recalls under the Excess Power Sales Agreement are made with respect to a "Summer Season" or a "Winter Season" (each a "Season"). The Excess Power Sales Agreement defines a "Summer Season" as each period beginning on March 25 and ending on the following September 24 and a "Winter Season" as each period beginning on September 25 and ending on the following March 24.

Based on the current schedules of power to be sold under the Excess Power Sales Agreement, which schedules are revised annually: (i) the recalling Utah Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess IPP Purchasers, until September 24, 2024, their IPP capability in excess of that which they have recalled; (ii) certain of the recalling Utah Purchasers have recalled IPP capability for various Seasons between March 25, 2024 and March 24, 2027, and may recall all or any portion of their remaining IPP capability for those Seasons and also may recall all or any portion of their IPP capability for Seasons thereafter until the term of the Excess Power Sales Agreement ends, subject to their compliance with the recall requirements thereof; and (iii) the remaining Utah Purchasers, if any, have committed, subject to certain permitted adjustments, to sell to the Excess IPP Purchasers, until September 24, 2024, their entire IPP capability, but may recall, subject to their compliance with the recall requirements of the Excess Power Sales Agreement, all or any portion of their IPP capability for any Season thereafter until the term of the Excess Power Sales Agreement ends.

For a description of the obligations of the respective IPP Purchasers to take or pay for capability of IPP, and the rights of the Utah Purchasers to recall capability of IPP, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" in the Agency ADR and "SUMMARY OF CERTAIN PROVISIONS OF THE POWER

SALES CONTRACTS" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in APPENDIX B to the Agency ADR.

The following table sets forth, as percentages, the capability of the Generation Station that each Original California Purchaser and the Utah Municipal Purchasers and the Cooperative Purchasers that have recalled such capability are obligated to purchase and pay for from and after March 25, 2024. The table is based on: (i) the percentage each Original California Purchaser purchases under its Power Sales Contract and, as to the Excess IPP Purchasers, the capability of the Generation Station each is presently committed to purchase under the Excess Power Sales Agreement; and (ii) the percentage of capability of the Generation Station that has been recalled by certain of the Utah Municipal Purchasers and the Cooperative Purchasers as described above. Any other recalls that may be effected hereafter will correspondingly decrease the percentages shown below for the Excess IPP Purchasers. See "POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT – Excess Entitlement Shares" in APPENDIX B to the Agency ADR.

Percentages of Capability of
Generation Station to be Purchased

IPP Purchaser	Winter Season beginning 25 Sep 2024	Winter Season beginning 25 Sep 2025	All Other Winter Seasons	Summer Season beginning 25 Mar 2024	Summer Season beginning 25 Mar 2025	All Other Summer Seasons
The Department	63.343%	62.126%	65.971%	58.965%	60.419%	65.795%
Anaheim	13.225	13.225	13.225	13.225	13.225	13.225
Riverside	7.617	7.617	7.617	7.617	7.617	7.617
Pasadena	5.699	5.592	5.929	5.315	5.443	5.913
Burbank	4.016	3.963	4.131	3.824	3.888	4.124
Glendale	2.111	2.077	2.183	1.990	2.030	2.178
Utah Municipal Purchasers	3.046	4.456	0.000	5.778	6.434	0.204
Cooperative Purchasers	0.944	0.944	0.944	3.286	0.944	0.944

Agreement for Sale of Renewal Excess Power. Pursuant to the Agreement for Sale of Renewal Excess Power referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Agreement for Sale of Renewal Excess Power" in the Agency ADR, for 50 years from and after the Transition Date, the Utah Renewal Purchasers have sold to the Department their entitlements to the use of the capability of IPP except for any portion of any such entitlement that a Utah Renewal Purchaser may, from time to time, recall under the Agreement for Sale of Renewal Excess Power. See "RENEWAL POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR SALE OF RENEWAL EXCESS POWER – Excess Entitlement Shares" in APPENDIX B to the Agency ADR.

IPP and the Generation Renewal Project

IPP. The Agency has acquired and constructed and is operating IPP, which consists of (i) a two-unit coal-fired steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah, (ii) a ±500-kV direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System"), (iii) two 50-mile 345-kV alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a

144-mile 230-kV alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"), (iv) a microwave communications system, (v) a railcar service center located in Springville, in Utah County, Utah (the "Railcar Service Center") and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station"). The operation and maintenance of IPP are being managed for the Agency by the Department in its capacity as Operating Agent.

All of the facilities of IPP have been in full commercial operation since May 1, 1987. See "IPP OPERATIONS – Management and Operation of IPP" herein for a description of the operating history of IPP.

IPP facilities have, generally, operated with a high degree of availability, exceeding the national average of coal-fired generating units of comparable size. In recent years, primarily due to market conditions, system demand, relatively low natural gas prices and the GHG Cost Factor (hereinafter defined), IPP has been noncompetitive relative to other resources available to the Original California Purchasers. The noncompetitive cost of IPP combined with the lack of coal fuel available in the region has resulted in IPP operating at less than industry-average capacity levels. Neither the Agency nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations of the coal units through the commercial operation date of the natural gas units described below that is scheduled to take place by July 1, 2025.

Generation Renewal Project. Further to the Agency's strategic planning initiatives (i) in 2015, the Agency and the IPP Purchasers amended the Power Sales Contracts to provide, among other things, for the repowering of IPP to consist of gas-fueled power blocks to replace the coal-fired units, with commercial operation of the gas units to be achieved by July 1, 2025 (such amendments to the Power Sales Contracts are hereinafter referred to as the "Power Sales Contracts Amendments," and such repowering of IPP is referred to in the Power Sales Contracts Amendments as the "Gas Repowering"); and (ii) the Coordinating Committee established pursuant to the Power Sales Contracts (the "Coordinating Committee") (see "COORDINATING COMMITTEE" herein) and the Agency's Board of Directors have approved (a) the development of capability to increase the percentage of hydrogen to be included in the mix of natural gas and hydrogen fuel to be burned in the gas units beyond the base capability of the gas units, which is 30% hydrogen by volume (the "Hydrogen Betterments"), along with (b) the entry into contracts with third parties to provide services for (i) natural gas transportation through 2045 (the "Natural Gas Transportation Contract"), and (ii) the conversion of water into hydrogen using renewable energy and the storage of such hydrogen, with the facilities necessary to provide such services (the "Hydrogen Conversion and Storage Capacity" and together with the Hydrogen Betterments, collectively, the "Hydrogen Facilities") to be substantially complete by October 1, 2024. The Gas Repowering, including the Natural Gas Transportation Contract, together with the development of the Hydrogen Facilities, including the Hydrogen Conversion and Storage Capacity, are referred to herein collectively as the "Generation Renewal Project"). Concurrently with the Generation Renewal Project, the Agency also is undertaking the replacement, renewal, and expansion of certain facilities of the Southern Transmission System to provide for an extension of the useful life thereof (as more fully described herein, the "STS Renewal Project").

Following the effectiveness of the Renewal Power Sales Contracts, the Department, in its capacity as a IPP Purchaser, requested, and IPP's governing bodies approved, a reduction in the design capacity and changes in the configuration of the natural gas facilities contemplated by the Power Sales Contracts Amendments (known under such contracts as an "Alternative Repowering"). Upon the effectiveness of the Alternative Repowering, the Power Sales Contracts were revised as necessary to describe the Alternative Repowering. Such revisions provide for the construction of two combined-cycle natural gas-fired power blocks, each power block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW, where "net generation capability" means gross power generation less auxiliary load for generation and transmission support. See "ELECTRIC INDUSTRY RESTRUCTURING – California Electric Energy Actions – *California Political Environment,*" "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases," "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Generation Renewal Project" and "INTERMOUNTAIN POWER AGENCY – The Interlocal Cooperation Act" in the Agency ADR.

Hydrogen Facilities

The costs of the Hydrogen Facilities (consisting of the Hydrogen Betterments and the Hydrogen Conversion and Storage Capacity) are being funded by the IPP Purchasers to the extent such elect to facilitate the development of such facilities. The costs of the Hydrogen Betterments are and some of the initial costs of the Hydrogen Conversion and Storage Capacity have been funded by payments to a "Hydrogen Betterments Fund" established by and funded pursuant to resolutions adopted by the Coordinating Committee, the Renewal Contract Coordinating Committee established pursuant to the Renewal Power Sales Contracts (the "Renewal Contract Coordinating Committee") (see "RENEWAL CONTRACT COORDINATING COMMITTEE" herein) and the Agency. The balance of the costs of the Hydrogen Conversion and Storage Capacity are being funded pursuant to the Hydrogen Billing Procedure described below. The Department and the Cities of Burbank and Glendale are the only IPP Purchasers that have elected to make payments to the Hydrogen Betterments Fund. The Agency bills those IPP Purchasers for such payments on a monthly basis. The Hydrogen Betterments Fund is not a fund or account established pursuant to the Agency's Power Supply Revenue Bond Resolution adopted on September 28, 1978, as supplemented, amended and restated from time to time (the "Resolution") and, therefore, is not a part of the Trust Estate (as defined in the Resolution), nor is it pledged as security for the payment of the Agency's Bonds.

In addition, on March 3, 2022, the Coordinating Committee, the Renewal Contract Coordinating Committee and the Agency approved a Hydrogen Billing Procedure (the "Hydrogen Billing Procedure") that provides for the Department and any other IPP Purchaser that elects to become a Hydrogen Purchaser (as defined in the Hydrogen Billing Procedure) to pay all of the costs associated with the hydrogen capabilities of IPP (including fixed costs for the Hydrogen Conversion and Storage Capacity and the variable costs of the hydrogen conversion and storage services). The costs for the Hydrogen Conversion and Storage Capacity and the variable costs for the use of such are estimated to be approximately $3,300,000,000 during the term of the contracts providing for such capacity and services, which is expected to be approximately 30 years. The costs addressed under the Hydrogen Billing Procedure represent costs that are not included in Monthly Power Costs (as defined in the Power Sales Contracts). The Hydrogen Billing Procedure provides for a reserve of $60,000,000 to be funded at a rate of $2,500,000 per month beginning in the Agency's fiscal year that commenced on July 1, 2022 (of which $52,500,000 has been funded as of the date of the Agency ADR). The Hydrogen Billing Procedure provides that the Hydrogen Purchasers will procure their hydrogen fuel from the Agency and that the Agency may condition such procurement on the execution of a fuel procurement contract between the Agency and each Hydrogen Purchaser which fuel procurement contracts would require approval of the Hydrogen Purchasers' respective governing bodies. The reserve established by the Hydrogen Billing Procedure is not a fund or account established pursuant to the Resolution and, therefore, is not a part of the Trust Estate, nor is it pledged as security for the payment of the Bonds.

STS Renewal Project

The Coordinating Committee and the Agency also have approved the STS Renewal Project as a capital improvement plan for the Southern Transmission System consisting of the replacement, renewal, and expansion of AC switchyards, reactive power equipment and associated facilities at the Adelanto Converter Station and the Intermountain Converter Station, the Cost of Acquisition and Construction (as defined in the Power Sales Contracts) for which is expected to be funded through payments-in-aid of construction to be made by the Southern California Public Power Authority ("SCPPA") to the Agency from the proceeds of bonds or other obligations of SCPPA issued and to be issued for such purpose, for the benefit of the Original California Purchasers. See "INTRODUCTION - Background; Development of the Southern Transmission System and Related Contracts" and "SOUTHERN TRANSMISSION SYSTEM AND THE PROJECT" in the Official Statement to which this Appendix is attached. As a result, it is not anticipated that such Cost of Acquisition and Construction of the STS Renewal Project will be paid from the proceeds of the Agency's Bonds or other obligations. The Agency will, however, be responsible for funding a portion of the shared costs incurred with respect to both the Gas Repowering and the STS Renewal Project. As of February 29, 2024, the Agency had expended approximately $370,000,000 (approximately 15%) of the $2.5 billion cost currently budgeted for the STS Renewal Project.

COORDINATING COMMITTEE

Pursuant to the Power Sales Contracts, the Coordinating Committee, among other functions, provides liaison among the Agency and the IPP Purchasers with respect to the construction and operation of IPP, reviews, modifies and approves certain specified contracts, takes certain actions with respect to actions of the Department, as Project Manager and Operating Agent, and makes recommendations to the Agency regarding the financing of IPP. The Coordinating Committee also has authority to review, modify and approve procedures formulated by the Project Manager and Operating Agent with respect to the construction and operation of IPP, budgets prepared by the Project Manager and Operating Agent, and all capital improvements proposed to be undertaken by the Agency.

The Coordinating Committee consists of the Chairman, who is a non-voting representative appointed by the Agency, and representatives of the IPP Purchasers or groups thereof. The Chairman of the Coordinating Committee may, at his own discretion, and must, at the request of any member of the Committee, call a meeting of the Committee. All actions taken by the Committee require the affirmative vote of representatives of IPP Purchasers having voting rights (which equal the respective IPP Purchasers' Generation Entitlement Shares) aggregating at least 80%.

The Coordinating Committee presently consists of its Chairman (the General Manager of the Agency), and the following voting representatives:

IPP Purchaser(s) Represented	**Representative**	**Voting Rights Percentage**
Murray City	Greg Bellon	4.000%
City of Logan	Mark Montgomery	2.469
All Other Utah Municipal Purchasers	Eric Larsen	7.571
Moon Lake Electric Association, Inc.	Yankton Johnson	2.000
Mt. Wheeler Power, Inc.	Kevin Robison	1.786
All Other Cooperative Purchasers	LaDel Laub	3.231
Department of Water and Power of The City of Los Angeles	Simon Zewdu	48.617
City of Anaheim	Dukku Lee	13.225
City of Burbank	Mandip Samra	3.371
City of Glendale	Mark Young	1.704
City of Pasadena	Sidney Jackson	4.409
City of Riverside	Todd M. Corbin	7.617
		100.000%

For additional discussion of the responsibilities and functions of the Coordinating Committee, see "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS – Coordinating Committee" and "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT – Coordinating Committee" in APPENDIX B to the Agency ADR.

RENEWAL CONTRACT COORDINATING COMMITTEE

Pursuant to the Renewal Power Sales Contracts, from and after the Transition Date, the Renewal Contract Coordinating Committee, among other functions, provides liaison among the Agency and the Renewal IPP Purchasers with respect to the construction and operation of IPP, reviews, modifies and approves certain specified contracts, takes certain actions with respect to actions of the Department, as Project Manager and Operating Agent, and makes recommendations to the Agency regarding the financing of IPP. From and after the Transition Date, the Renewal Contract Coordinating Committee also has authority to review, modify and approve procedures formulated by the Project Manager and Operating Agent with respect to the construction and operation of IPP, budgets prepared by the Project Manager and Operating Agent, and all capital improvements (other than Essential Capital Improvements, as defined in the Renewal Power Sales Contracts) proposed to be undertaken by the Agency. Prior to the Transition Date, the Renewal Contract Coordinating Committee's authority is limited to considering matters related to Transition Project Indebtedness (as defined below) and other matters requiring Renewal Contract Coordinating Committee approval prior to the Transition Date pursuant to the Power Sales Contracts or the Renewal Power Sales Contracts and to receive financial statements and operating reports provided to the Coordinating Committee in the ordinary course of business. The Renewal Contract Coordinating Committee's approval is required for the issuance of Transition Project Indebtedness for purposes other than financing the Gas Repowering (so long as the Transition Project Indebtedness satisfies the requirements related to Substantially Equal Debt Service, as defined in the Renewal Power Sales Contracts). "Transition Project Indebtedness" is defined in the Power Sales Contracts to mean Bonds (as defined in the Power Sales Contracts) or other obligations issued by the Agency prior to June 16, 2027 that by their terms shall be scheduled to remain outstanding after June 16, 2027.

The Renewal Contract Coordinating Committee consists of the Chairman, who is a non-voting representative appointed by the Agency, and representatives of the Renewal IPP Purchasers or groups thereof. The Chairman of the Renewal Contract Coordinating Committee may, at his own discretion, and must, at the request of any member of the Renewal Contract Coordinating Committee, call a meeting of the Renewal Contract Coordinating Committee. All actions taken by the Renewal Contract Coordinating Committee require the affirmative vote of representatives of IPP Purchasers having voting rights (which equal the respective IPP Purchasers' Generation Entitlement Shares) aggregating at least 80% (except that modifications affecting the minimum cost component of Project Fuel, as permitted under the Renewal Power Sales Contracts, require 100% of such voting rights).

The Renewal Contract Coordinating Committee presently consists of the General Manager of the Agency, as Chairman, and the following voting representatives:

IPP Purchaser(s) Represented	Representative	Voting Rights Percentage
Murray City	Greg Bellon	4.036%
City of Logan	Mark Montgomery	2.491
City of Bountiful	Allen Johnson	1.711
All Other Utah Municipal Purchasers	Eric Larsen	5.737
Moon Lake Electric Association, Inc.	Yankton Johnson	2.018
Mt. Wheeler Power, Inc.	Kevin Robison	1.803
All Other Cooperative Purchasers	LaDel Laub	3.261
Department of Water and Power of The City of Los Angeles	Simon Zewdu	71.442
City of Burbank	Mandip Samra	3.334
City of Glendale	Mark Young	4.167
		100.000%

For additional discussion of the responsibilities and functions of the Renewal Contract Coordinating Committee, see "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS – Renewal Contract Coordinating Committee" in APPENDIX B to the Agency ADR.

IPP OPERATIONS

General

IPP's coal-fired steam-electric generating plant and associated facilities were constructed to provide the IPP Purchasers with reliable electrical energy while reducing their dependence on oil- and natural gas-fired generation. This section briefly describes the construction, management and operation of IPP, its delivery of energy, and certain matters affecting IPP operations (such as fuel and water supplies, government licenses and permits, and insurance).

Management and Operation of IPP

Management and Work Force. IPP operations are managed for the Agency by the Department under the terms of the Construction Management and Operating Agreement. The Department's operating activities are subject to the oversight of the Coordinating Committee. See "COORDINATING COMMITTEE" herein. In operating the Intermountain Generating Station, the Intermountain Converter

Station and the Railcar Service Center, the Operating Agent uses personnel from Intermountain Power Service Corporation, a Utah nonprofit corporation ("IPSC"). The International Brotherhood of Electrical Workers has been certified as the collective bargaining representative of IPSC employees. The collective bargaining agreement between these parties was renewed on July 1, 2022 and expires on June 30, 2026. Remaining IPP facilities are managed by the Operating Agent's own personnel.

Operating Experience. Generally, IPP facilities have operated with a high degree of availability, exceeding the average of coal-fired generating units of comparable size. Neither the Agency nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations on a long-term basis.

The Agency has seen, however, a decline in the utilization of IPP since 2016 as a result of the California GHG initiatives. Such GHG initiatives are expected to put downward pressure on the utilization rate of IPP for the foreseeable future. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases" in the Agency ADR.

Removal of Coal Units from Service. On May 22, 2017, the Agency's Board of Directors determined that the coal-fired units at IPP will be removed from service by the commercial operation date of the gas-fired power blocks to be constructed as part of the Generation Renewal Project (which is scheduled for 2025). The Coordinating Committee approved the removal as well. In response to requirements of the CCR Rule (as defined below), the Agency has determined to cease operation of the coal-fired boilers by the deadline of 2028 imposed in the CCR Rule. The Agency anticipates that based on its intended course of action to remove the coal-fired units from service by 2025, it will have satisfied the requirement of the CCR Rule to cease operation of the coal-fired boilers in advance of the deadline under the CCR Rule. The "CCR Rule" means the final coal combustion residuals ("CCR") rule promulgated by EPA in April 2015 and which became effective in October 2015, which regulates the disposal and management of CCR as non-hazardous under Subtitle D of the federal Resource Conservation and Recovery Act. The Agency does not interpret Utah law to require the operation of the coal-fired boilers beyond July 1, 2025.

Operating Statistics. The operating results of IPP during fiscal years 2019-2020 through 2022-2023 are shown in the following table. Based on the historical experience of comparable generating units, IPP would be expected to continue to achieve, until commercial operation of the Generation Renewal Project, the above-average levels of performance demonstrated to date with respect to the following metrics set forth in the table below: Operating Availability, Equivalent Availability and Net Unit Heat Rate (expressed as BTU per kilowatt hour ("kWh")). IPP is not expected to achieve above-average levels of performance with respect to the metric of Plant Capacity Factor shown in the table below. The Agency anticipates that IPP's capacity factor (and, consequently, Gross Energy Generated (expressed in megawatt hours ("MWh")) and Net Energy Generated (expressed in MWh) will depend on system demand, market conditions and the application of the GHG Cost Factor, and may be impacted by other factors discussed elsewhere in the Agency ADR. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases" in the Agency ADR.

	Fiscal Year 2019-20[1]	Fiscal Year 2020-21[2]	Fiscal Year 2021-22[3]	Fiscal Year 2022-23[4]	Industry Average Calendar Years 2018-2022[5]
Gross Energy Generated (MWh)					
Unit 1	3,724,186	3,808,747	3,126,525	2,764,193	3,555,789
Unit 2	3,642,927	4,070,442	2,969,883	3,714,375	3,555,789
Net Energy Generated (MWh)					
Unit 1	3,443,031	3,537,724	2,873,350	2,538,344	3,358,376
Unit 2	3,362,157	3,763,675	2,731,012	3,418,622	3,358,376
Plant Capacity Factor[6]					
Unit 1	43.55%	44.87%	36.45%	32.20%	45.81%
Unit 2	42.53%	47.74%	34.64%	43.36%	45.81%
Operating Availability[7]					
Unit 1	96.53%	85.20%	95.66%	88.07%	79.82%
Unit 2	93.27%	94.91%	84.02%	97.16%	79.82%
Equivalent Availability[8]					
Unit 1	96.48%	85.17%	95.66%	87.80%	77.47%
Unit 2	93.21%	94.36%	83.87%	97.16%	77.47%
Net Unit Heat Rate (BTU/kWh)[9]					
Unit 1	10,428	10,174	10,227	10,182	10,839
Unit 2	10,324	10,247	10,122	10,167	10,839

(1) Reflects outages during the 2019-2020 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 2 spring 2020 (3.49 weeks) and Unit 1 spring 2020 (8.86 days)), unplanned maintenance outages (Unit 1 (0 days) and Unit 2 (0 days) and forced outages (Unit 1 (3.86 days) and Unit 2 (0.22 days)).

(2) Reflects outages during the 2020-2021 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 1 spring 2021 (7.24 weeks) and Unit 2 spring 2021 (9.30 days)), unplanned maintenance outages (Unit 1 (3.24 days) and Unit 2 (5.90 days) and forced outages (Unit 1 (0.07 days) and Unit 2 (3.37 days)).

(3) Reflects outages during the 2021-2022 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 2 spring 2022 (8.29 weeks) and Unit 2 spring 2022 (11.82 days)), unplanned maintenance outages (Unit 1 (0.00 days) and Unit 2 (0.00 days) and forced outages (Unit 1 (4.02 days) and Unit 2 (0.28 days)).

(4) Reflects outages during the 2022-2023 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 1 spring 2023 (6 weeks) and Unit 2 spring 2023 (10 days)), unplanned maintenance outages (Unit 1 (0 days) and Unit 2 (0 days) and forced outages (Unit 1 (0.18 days) and Unit 2 (0.43 days)).

(5) Industry average figures except heat rate are as reported by the North American Electric Reliability Corporation ("NERC") for coal-fired units rated 800-999 MW and are the composite averages of 51 units in the years 2018 through 2022 (5-year average), which is the most recent information currently available. Average net station heat rate is compiled and cited from Form EIA-923 released by the Energy Information Administration of the U.S. Department of Energy ("EIA") for 2022 for the top 25 largest western coal-fired power plants. Such NERC and EIA reports are calendar-year based.

(6) The Plant Capacity Factor for a unit is the ratio of the net energy generated by that unit to the net maximum capability of that unit times the hours in the period and reflects the unit availability as well as the actual power produced by the unit.

(7) The Operating Availability is the ratio of hours in the period that the unit is capable of operating at some level to the number of hours in the period.

(8) The Equivalent Availability Factor provides an adjustment of the Operating Availability by incorporating the effect of de-ratings (losses in MW capability) and is essentially equivalent to the percentage of time during a period during which a unit was available for maximum net capability operation.

(9) The Unit Heat Rate is a measure of the efficiency of the unit and shows the amount of heat energy in BTUs necessary to produce 1.0 net kWh. The smaller this number is, the more efficient the unit.

IPP Energy Delivery

The output of IPP is delivered to the IPP Purchasers at points of delivery designated by them from among the Switchyard, the Mona and Gonder Switchyards of the Northern Transmission System, and the Adelanto Converter Station of the Southern Transmission System. Each of the IPP Purchasers is responsible for providing for transmission of its entitlement of Intermountain Generating Station output from its designated point of delivery to its electric system.

The Original California Purchasers have each designated the Adelanto Converter Station as their point of delivery. The Adelanto Converter Station is connected with the Department's main transmission system, and the Department takes delivery of its entitlement of Intermountain Generating Station output at the Adelanto Converter Station. Transmission services for Original California Purchasers Glendale and Burbank to their electric systems are provided by the Department. Transmission services for Original California Purchaser Pasadena to its electric system are currently provided by the Department and the CAISO. The CAISO handles deliveries for Anaheim and Riverside. The Adelanto Converter Station also is connected to the Mead-Adelanto Transmission Project (as described in the Official Statement to which this Appendix is attached).

PacifiCorp provides transmission services for the Utah Purchasers, except: (i) Mt. Wheeler Power, Inc. (which has designated the Gonder Switchyard as its point of delivery and takes delivery of its power from other sources at that point); and (ii) Moon Lake Electric Association, Inc. (which has made arrangements to use facilities that have been constructed by Deseret Generation & Transmission Co-operative in connection with its Bonanza project).

The Utah Municipal Purchasers are members of UAMPS, which has entered into a long-term transmission agreement with PacifiCorp under which PacifiCorp provides certain transmission services for the members of UAMPS, including transmission of the Utah Municipal Purchasers' entitlement to IPP power from the Mona Switchyard to the Utah Municipal Purchasers' respective points of delivery for their distribution systems.

Interconnections to IPP

In the spring of 2008, the Agency and Milford Wind I entered into a Generator Interconnection Agreement (the "GIA"). Pursuant to the GIA, the Agency granted to Milford Wind I the right, subject to the terms, conditions and limitations of the GIA, to interconnect the Milford Wind I Project to the transmission systems of IPP through the Switchyard. The GIA, however, grants Milford Wind I no right or entitlement to use any of the capacity of the Switchyard, the Southern Transmission System or the Northern Transmission System. Rather, Milford Wind I is permitted to connect to IPP transmission facilities for the purpose of delivering capacity and energy from the Milford Wind I Project through the Switchyard only if and to the extent adequate transmission capacity is made available to Milford Wind I by IPP Purchasers, subject to the maximum amount of megawatts identified in certain applicable stability and steady state studies.

Pursuant to an assignment of a portion of Milford Wind I's entitlement to Milford Wind II, in 2010, the Agency and Milford Wind II negotiated and executed a GIA. The second GIA provides for interconnection capacity for the Milford Wind II Project, in addition to the Milford Wind I Project, to the transmission systems of IPP through the Switchyard.

Certain of the Original California Purchasers have arranged to take delivery of all power delivered by the Milford Wind Projects at a point immediately before the point at which Milford Wind I's and Milford Wind II's transmission lines cross the boundary of the Switchyard. The Original California Purchasers are using and anticipate using entitlements in the Southern Transmission System that they currently hold and that they may acquire to connect such power to the Southern Transmission System through the Switchyard, and transmit it to their point of delivery at Adelanto, California. With the completion of an upgrade of the Southern Transmission System completed in 2010, the Original California Purchasers have, and the California Renewal Purchasers will have, sufficient capacity to transmit this power. Pursuant to the Power Sales Contracts and the Renewal Power Sales Contracts, power generated by the Intermountain Generating Station takes priority, however, over any power generated by any other sources for purposes of scheduling the capacity and use of the Switchyard and transmission systems of IPP.

In 2010, the Agency also granted interconnection rights to the Department at the Adelanto Converter Station for delivery of up to 10 MW of power generated by the Department's solar project near Adelanto, California. In December 2022, the Agency signed generator interconnection agreements with five projects to interconnect at the Switchyard a total of 1,724 MW of renewable energy generation and 1,444 MW of battery energy storage, with a maximum output of 1,724 MW. An additional interconnection project comprised of 285 MW of solar generation and 285 MW of battery energy storage is pending execution of a generator interconnection agreement.

The Agency has nine additional active interconnection requests in various stages in the generation interconnection queue, including wind and solar energy and battery energy storage with maximum output of 4,575 MW. The Agency also has four renewable electricity generation and battery storage projects which plan to interconnect to interconnection facilities owned by other entities with respect to which the Agency will study potential reliability impacts to its transmission system. In addition, there are two non-generator interconnection requests being studied as part of the Agency's interconnection procedures. The Agency review of the applications includes performing system impact studies, harmonics studies and facilities studies to determine the cost of interconnection facilities and any necessary network upgrades. See "ELECTRIC INDUSTRY RESTRUCTURING – Federal Electric Energy Actions – *FERC Open-Access Transmission Initiatives*" in the Agency ADR.

Fuel Supply

During fiscal year 2022-2023, Unit 1 operated at a plant capacity factor of 32.20% and Unit 2 operated at a plant capacity factor of 43.36%. Coal consumption during that fiscal year was approximately 2.676 million tons.

The Agency possesses coal supply agreements to fulfill the supply requirement of approximately 3.0 million tons in calendar year 2024 and 1.0 million tons in calendar year 2025. The coal is purchased under a portfolio of fixed-price contracts that are of short- and long-term in duration. However, supply chain issues dramatically reduced coal supply beginning in the later months of 2021 and are expected to impact coal supply for the remaining life of the coal plant. The largest coal producer in Utah experienced a fire in September 2022 leading to the mine being closed permanently in December 2023. The loss of the largest Utah coal mine, combined with the logistics challenges in Utah, has dramatically reduced supply in the region including to the Agency.

The cost of coal delivered to the Intermountain Generating Station is similar to current market prices for the region. The Agency expects that the costs to fulfill IPP's annual coal supply requirements will increase due to the scarcity of coal in the Western United States and increased transportation costs to purchase from more distant regions, if the Agency is able to secure any additional coal.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between the Agency and the Union Pacific Railroad company, and the coal is transported, principally, in railcars owned by the Agency. A small volume of coal is also transported to IPP in commercial trucks. Both rail service and trucking services have suffered greatly by a lack of human resources. Neither network is capable of supporting industrial demand; and the Agency, like all coal-fired utilities in the United States, has seen large systemic failures in the transportation system.

Historically, IPP was able to maintain a minimum of 60 days of coal in inventory in the event of a coal supply disruption. However, challenges in the coal supply chain resulted in only 35 days of inventory at the end of calendar year 2023.

Through the execution of the Natural Gas Transportation Contract, the Agency has secured firm natural gas transportation capacity sufficient to deliver 100% of the natural gas required to operate the Generation Renewal Project at projected capacity factors through 2045. In March 2024, the Agency executed a Fuel & Asset Management Agreement (the "FAMA") with Tenaska Marketing Venture ("TMV"). TMV will provide 100% of the test gas to IPP as early as September 2024. Under the FAMA, TMV is also responsible for nominating, scheduling, and delivering natural gas to IPP through the Natural Gas Transportation Contract. Also in March 2024, the Agency executed seven North American Energy Standards Board ("NAESB") base contracts with gas suppliers. IPP continues to seek natural gas suppliers and producers to diversify its natural gas supply pool.

Water Supply

The Agency owns water rights and water shares (primarily from the Sevier River) that, combined, yield an average of approximately 45,000 acre-feet per year. This amount exceeds the annual water requirements of the Intermountain Generating Station and the Intermountain Converter Station. Should there be an interruption in the water supply system customarily used for operation of the Intermountain Generating Station and the Intermountain Converter Station, a reservoir at the Intermountain Generating Station, in combination with ground-water wells, can provide sufficient water to operate the Intermountain Generating Station and the Intermountain Converter Station for about twenty-five (25) days at full plant loads. See "RISK FACTORS – Drought" in the Agency ADR.

IPP currently uses approximately 12,500 acre-feet annually. Following construction of the Generation Renewal Project (and the replacement of the coal units by the Generation Renewal Project), water usage is projected to be reduced to approximately 6,500 acre-feet per year.

The Agency has made and anticipates continuing to make water available for development of the salt caverns for storage of hydrogen fuel in the amount of approximately 7,000 acre-feet per year through 2026, if needed. The Agency projects that annual water usage for hydrogen fuel production could increase by a maximum of approximately 2,400 acre-feet (assuming that all energy at IPP is generated using 100% hydrogen fuel).

The Agency's water rights (and the water rights underlying its water shares) were permitted by the State of Utah assuming that 100% of the water used in IPP would constitute depletion (i.e., no water used by IPP would return to the water system from which the water is drawn pursuant to the Agency's water rights and water shares). A significant portion of the water used by IPP each year is, in fact, returned to the water system from which it has been taken.

Permits, Licenses and Approvals

To the Agency's knowledge, IPP has been designed, constructed and operated in compliance with all applicable federal, state and local regulations, codes, standards and laws. To the Agency's knowledge, all principal permits, licenses, grants and approvals required to construct and operate the current facilities of IPP have been acquired, including permits relating to air quality and rights-of-way on federally-owned land.

The Agency has obtained all principal permits necessary for design, construction and operation of the Gas Repowering (other than the Natural Gas Transportation Contract), the Hydrogen Betterments and the STS Renewal Project. The air permit from the Utah Department of Air Quality has been issued for the Gas Repowering. Permitting under the Natural Gas Transportation Contract and with respect to the Hydrogen Conversion and Storage Capacity are the responsibilities of the respective third parties with which the Agency has contracted for such transportation, conversion and capacity. The Agency expects the third parties to receive the necessary permits in a timely manner.

Insurance

Pursuant to the Resolution, the Agency is required to use its best efforts to insure or cause to be insured the properties of IPP which are of an insurable nature and of the character usually insured by those operating properties similar to IPP against loss or damage by fire and from other causes customarily insured against and in such relative amounts and having such deductibles as are usually obtained. The Resolution also requires the Agency to use its best efforts to maintain or cause to be maintained insurance or reserves against loss or damage from hazards and risks to the person and property of others as are usually insured or reserved against by those operating properties similar to the properties of IPP. The Operating Agent acts as the Agency's agent in obtaining and maintaining insurance for IPP.

The Agency's insurance program for IPP consists of a combination of commercial insurance policies, fidelity bonds and self-insurance. In the opinion of the Operating Agent, the coverages and limits provided by the Agency's insurance program conform to those customarily provided by utilities in the public power industry. In connection with its self-insurance program, the Agency has established the Self-Insurance Fund under the Resolution. See "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Application of Revenues" and "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Insurance" in APPENDIX A to the Agency ADR.

LITIGATION

General

Except as described below, there is no litigation or other proceeding pending or, to the knowledge of the Agency, threatened in any court, agency or other administrative body (either state or federal) that the Agency anticipates would have any material adverse effect upon the condition (financial or otherwise) of the Agency or the results of its operations.

Appeals of Fees in Lieu of Property Taxes

In the State of Utah, each year the Property Tax Division of the Utah State Tax Commission (the "Division") determines the value of the Agency's tangible property located within the State of Utah (the "Taxable Tangible Property") and then various counties in Utah (the "Counties") assess fees in lieu of property tax (the "Fees") to the Agency based on such valuation. The Division's annual valuations are subject, during a specified period, to the right of the Agency or the Counties to appeal such valuations to the Utah State Tax Commission (the "Commission"). When a valuation is appealed to the Commission, the appeal is tried before the Commission as the adjudicative body. In such an appeal, the Commission has the obligation to determine the fair market value of the Taxable Tangible Property. The Division has the right to appear as a party before the Commission in such an appeal to defend the Division's valuation as being equal to fair market value.

The Agency has appealed the Division's valuation of the Taxable Tangible Property for each of the years 2014 through 2022 (the relevant Fees will be determined by a statutory formula that is to be calculated solely on the basis of the valuation that will be determined by a final nonappealable decision of the Commission or the court). The Agency has paid the assessed Fees for each year on appeal and is seeking to obtain a refund of the Fees attributable to the amount by which the Division's valuation of the Taxable Tangible Property exceeds the fair market value of the Taxable Tangible Property. The appeal of the 2014 Valuation (as defined below) has been heard by the Commission.

The Fees assessed by the Counties to the Agency in 2014 (the "2014 Fees") were based on the valuation by the Division of the Taxable Tangible Property at $829,450,170 (the "2014 Valuation"). After the Counties assessed the 2014 Fees, the Division asserted that the 2014 Valuation reflected a computational error and that the Taxable Tangible Property had a value in 2014 of $1,031,520,000. In connection with the Agency's appeal of the 2014 Valuation, the seven Counties that are the beneficiaries of the 2014 Fees asserted a valuation that was approximately the same as the valuation that the Division asserted after the assessment of the 2014 Fees. The Agency asserted that, for 2014, the Taxable Tangible Property had a fair market value of $499,000,000.

The 2014 Fees have reflected the Division's exclusion from the Fee base of a percentage of the Fee base equal to the percentage of power purchased from the Agency by the Utah Municipal Purchasers (the "Municipal Exclusion"). The State of Utah has conceded in assessing the 2014 Fees (and in earlier years) that since the Agency sells at least a portion of IPP's generation capacity and output to Utah municipalities pursuant to the Power Sales Contracts between the Agency and such municipalities, a proportionate portion of the value of the Agency's Taxable Tangible Property should be excluded from the Fee base in calculating the Fees. The 2014 Valuation and the valuation advocated by the Agency in the appeal of the 2014 Valuation reflected a Municipal Exclusion of 14.04%. The valuation proposed by the Division following such assessment reflected a Municipal Exclusion of 11.193% (reflecting a change in the Division's position following the assessment of the 2014 Fees).

After the trial of the 2014 Valuation (held in 2016), the Division, Millard County and the Agency filed their respective briefs setting forth their positions with respect to the Municipal Exclusion. In those briefs, the Agency, the Division and Millard County asserted that the Municipal Exclusion should be equal to 14.04%, 11.193% and 0%, respectively.

On December 22, 2017, the Commission issued its decision with respect to the 2014 Valuation. The Commission ordered that the value of the Taxable Tangible Property be $751,495,000 (after giving effect to a Municipal Exclusion of 14.04%). The Counties appealed the Commission's decision to a Utah state district court (sitting as a tax court, the "Tax Court"). The Agency then cross-appealed the Commission's order. Because the Division is a division within the Commission, the Division has no right to appeal the Commission's decision with respect to the 2014 Valuation (including the amount of the Municipal Exclusion). The Commission does have the right to appear in the Tax Court proceedings to argue that the Tax Court should uphold the Commission's order.

The appeal to the Tax Court, if it is not resolved through settlement before trial, will result in a trial de novo (with no deference to the findings of fact or conclusions of law made by the Commission). The appeal to the Tax Court has stayed any refunds required to be made by the Counties pursuant to the Commission's order pending a final non-appealable order. The Tax Court has ordered that the Agency and the Counties proceed with discovery in the appeal. The Tax Court will set the date for trial of the appeal once discovery is complete. Discovery is nearly complete. There are presently ongoing discussions relating to a potential deposition of a third party. The timeline for discovery is subject to continued extensions.

The Agency, the Commission, and the Counties have filed a stipulation with the Tax Court providing that the proceedings in the appeals are to be protected from public disclosure.

Any of the Counties or the Agency may appeal a decision by the Tax Court directly to the Utah Supreme Court. Although the parties would have the right to have such appeal heard, the Utah Supreme Court has the discretion to hear the appeal itself or to have the appeal heard by the Utah Court of Appeals. If the Utah Supreme Court elects to have the Utah Court of Appeals hear the appeal, the Utah Supreme Court would then have the discretion to decline to hear any appeal of the Utah Court of Appeals' decision.

The Commission has ordered that the appeals regarding Valuations for 2015 through 2022 be stayed to allow the appeal of the 2014 Valuation to be tried in court.

In the fall of 2023, Millard County determined that an offer of settlement of the appeal was acceptable to the county. The Agency is working with Millard County, the other Counties involved in the appeals and the State of Utah to document and approve the terms of the settlement.

The Agency cannot predict the outcome of any appeal of the Commission's order including with respect to the assessed value of the Agency's property. The Tax Court will not be limited to the original determination by the Commission of fair market value made in connection with the assessment of the 2014 Fees. The Tax Court, with respect to the 2014 appeals, or the Commission, with respect to the appeals for the remaining years, may determine that the fair market value of the Taxable Tangible Property exceeds the valuation for the year or years before it or that the Municipal Exclusion is as low as 0% (concluding that the Agency would owe more fees), including even if the Agency withdrew its appeal.

The Agency cannot predict whether the terms of the settlement proposal described above will be acceptable to all of the Counties and the State or whether the parties will be able to finalize the settlement proposal. If the settlement is not finalized, the Agency cannot predict the effect that the Commission's or a reviewing court's decision with respect to the 2014 Valuation or the 2014 Fees, including the impact of the decision following the exhaustion of any appeals (during the pendency of which the Commission's order is stayed), will have on the Commission's determinations with respect to the valuation or the Fees with respect to later years on appeal. The Agency cannot predict the impact on the Agency's financial condition, if any, from enforcement of the Commission's decision with respect to the 2014 Valuation and the 2014 Fees, an adverse determination by a reviewing court with respect to the 2014 Valuation or the 2014 Fees or the determination by the Commission or a reviewing court with respect to the valuation or the Fees for subsequent years.

SCPPA
Southern California Public Power Authority

AGENDA ITEM STAFF REPORT

MEETING DATE: April 18, 2024

RESOLUTION NUMBER: 2024-016
2024-017

SUBJECT: Refunding of the Apex Power Project, Revenue Bonds, 2014 Series A (Tax-Exempt) and 2014 Series B (Federally Taxable)

DISCUSSION: ☒ **OR** **CONSENT:** ☐

Select the appropriate box(es):

FROM:		**METHOD OF SELECTION:**	
Finance	☒	Competitive	☐
Project Development	☐	Cooperative Purchase	☐
Program Development	☐	Sole Source	☐
Regulatory/Legislative	☐	Other	☒
Project Administration	☐	*Other (Please describe):*	
Legal	☐	In accordance with SCPPA Policy for Financing and Selection of Financing Team	
Executive Director	☐		

MEMBER PARTICIPATION:

Sponsoring Member: LADWP

Other Members Potentially Participating: None

Approved by Interim Executive Director: DocuSigned by: Randolph R. Krager
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RECOMMENDATION:

Adopt Resolution Number 2024-016 authorizing the refunding of Apex Power Project, Revenue Bonds, 2014 Series A (Tax-Exempt) and 2014 Series B (Federally Taxable) and the execution and delivery of various agreements relating to the issuance of refunding revenue bonds and Resolution Number 2024-017approving the provision of certain Continuing Disclosure information with respect to the refunding revenue bonds.

BACKGROUND:

SCPPA currently has outstanding $230,035,000 in Apex Power Project, Revenue Bonds, 2014 Series A and B. The 2014 Series A are fixed rate tax-exempt bonds issued in the amount of $151,880,000 with a final maturity date of July 1, 2038, and are fully outstanding. The 2014 Series B are fixed rate federally taxable bonds issued in the amount of $166,980,000 with a final maturity date of July 1, 2030, of which $78,155,000 is currently outstanding. Both bond series have an optional redemption date of July 1, 2024.

The bonds were issued in 2014 to finance the cost of acquisition of the Apex Power Project ("Project"), and the costs of certain replacement parts for, capital improvements to, and insurance and other initial costs for the Project. The Project is a natural gas-fired, combined cycle generating facility, nominally rated at 531 MW, located in Clark County, Nevada.

The Los Angels Department of Water and Power ("LADWP") is the sole SCPPA Member participant in the Project.

DISCUSSION:

The current plan of finance anticipates issuing fixed rate tax-exempt refunding revenue bonds to refinance the outstanding 2014 Series A and B bonds, amortizing to the same final maturity in 2038.

Currently, bond pricing is anticipated to be in May 2024 with the transaction closing in early June 2024.

On March 21, 2024, the Board of Directors adopted Resolution No. 2024-011 authorizing the preparation of all documents necessary for the refunding of the Apex Power Project, Revenue Bonds, 2014 Series A and B.

The first Resolution, 2024-016, (Authorizing Resolution) attached will authorize the issuance of the refunding revenue bonds and the execution and delivery of the various documents relating to the refunding revenue bonds, including those attached to this report. The second Resolution, 2024-017, (Continuing Disclosure Resolution) attached will authorize provision for certain Continuing Disclosure information with respect to the refunding bonds. The Finance Committee recommended approval of the two Resolutions at the April 4, 2024 Finance Committee meeting.

- **Selection Method:**

  The financing team has been assembled and consists of SCPPA staff, Project participant's staff, Norton Rose Fulbright US LLP serving as Bond and Disclosure Counsel, Nixon Peabody LLP serving as Special Tax Counsel, and PFM Financial Advisors LLC serving as Financial Advisors.

  The Finance Committee recommended the selection of J.P. Morgan Securities LLC from SCPPA's established underwriting pool to serve as the senior managing underwriter and PNC Capital Markets LLC to serve as co-manager. The Finance Committee considered the qualification criteria as provided in SCPPA's Policy for Financing and Selection of the Financing Team taking into consideration the firm's experience and coverage of SCPPA and provided its recommendation on the firms that will deliver the overall best value for the transaction.

Additional members of the financing team include US Bank serving as the Trustee/Escrow Agent and a Verification Agent that will be selected closer to the bond pricing date. Fees for services will be paid from bond proceeds.

- **SCPPA's Authority:**

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  The refinancing of the Apex Power Project revenue bonds is in accordance with the California Joint Exercise of Powers Act and the SCPPA Joint Powers Agreement. The SCPPA Joint Powers Agreement provides the authority for SCPPA to finance generation and transmission projects, including the refinancing of such projects.

FISCAL IMPACT:

The refunding is expected to generate debt service savings. Based on market conditions as of the end of March 2024, the net present value of savings was approximately $31 million. Actual savings will depend on the market conditions at the time of bond pricing.

Exhibit A of the Authorizing Resolution provides good faith estimates of various financial information regarding the refunding bonds to be issued, which include principal amount, true interest cost, finance charge, amount of proceeds, and total payment.

ATTACHMENT:

1. Resolution No. 2024-016 – Authorizing Resolution
2. Resolution No. 2024-017 – Continuing Disclosure Resolution
3. Third Supplemental Indenture of Trust
4. Purchase Contract
5. Preliminary Official Statement

[Project Vote: LADWP]

RESOLUTION NO. 2024-016

RESOLUTION RELATING TO THE APEX POWER PROJECT: AUTHORIZING (I) THE ISSUANCE OF REFUNDING BONDS FOR THE APEX POWER PROJECT; (II) THE EXECUTION AND DELIVERY OF (A) A THIRD SUPPLEMENTAL INDENTURE OF TRUST RELATING TO THE APEX POWER PROJECT, REFUNDING REVENUE BONDS, 2024 SERIES A AND (B) A PURCHASE CONTRACT; (III) THE DELIVERY OF A PRELIMINARY OFFICIAL STATEMENT AND THE EXECUTION AND DELIVERY OF AN OFFICIAL STATEMENT; (IV) CERTAIN RELATED ACTIONS; AND (V) THE OFFICERS OF THE AUTHORITY TO DO ALL OTHER THINGS DEEMED NECESSARY OR ADVISABLE

WHEREAS, in order to provide a portion of the funds needed to acquire the Apex Power Project for the benefit of the Department of Water and Power of The City of Los Angeles ("LADWP" or the "Project Participant"), on March 26, 2014 the Southern California Public Power Authority (the "Authority") issued $151,880,000 principal amount of its Apex Power Project, Revenue Bonds, 2014 Series A (Tax-Exempt) (the "2014 Series A Bonds") and $166,980,000 principal amount of its Apex Power Project, Revenue Bonds, 2014 Series B (Federally Taxable) (the "Series 2014 B Bonds"); and

WHEREAS, on April 4, 2024, the Finance Committee of the Authority recommended that the Authority, if approved by the Board of Directors, proceed with the refunding of the outstanding 2014 Series A Bonds and the outstanding 2014 Series B Bonds (together, the "Refunded Bonds") through the issuance by the Authority of its Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the "Bonds"); and

WHEREAS, in connection with the issuance of the Bonds, the Authority wishes to prepare and distribute an Official Statement (in preliminary and final form) describing, among other things, the terms of the Bonds, the Apex Power Project, LADWP and various terms of the documents relating to the Bonds and the transactions contemplated by this Resolution; and

WHEREAS, there has been presented to this meeting proposed forms of certain financing documents relating to the Bonds;

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority as follows:

1. Each of the President, any Vice President, the Executive Director (references to Executive Director herein including any Interim Executive Director) and the Chief Financial and Administrative Officer of the Authority (each, an "Authorized Representative") is hereby authorized to execute and deliver a Third Supplemental Indenture of Trust relating to the Bonds, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), in the form on file with an Assistant Secretary of the Authority, with such changes,

insertions and omissions (subject to Paragraph 6 hereof) as shall be approved by said Authorized Representative (such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof); and each of the Secretary and any Assistant Secretary of the Authority is hereby authorized to attest and to affix thereto the seal of the Authority thereto. The Third Supplemental Indenture of Trust, as executed and delivered, is hereinafter referred to as the "Third Supplemental Indenture." Proceeds of the Bonds shall be used primarily to refund all or a portion of the Refunded Bonds. The Third Supplemental Indenture on file with an Assistant Secretary is hereby made a part of this Resolution as though set forth in full herein and the same hereby is approved.

The issuance of the Bonds is hereby authorized, subject to the provisions of this Resolution, the Indenture of Trust, dated as of March 1, 2014 (as heretofore amended and supplemented, the "Indenture") from the Authority to the Trustee, and the Third Supplemental Indenture. The Bonds shall be dated, shall mature on the dates and in the years and shall bear interest all as provided in the Indenture and the Third Supplemental Indenture. The form of the Bonds and the provisions for signatures, authentication, payment, registration, numbers, denominations, redemption (if any), sinking fund installments (if any) and other terms thereof shall be as set forth in the Indenture and Third Supplemental Indenture.

The Bonds shall be secured by the pledge effected by the Indenture and shall be special, limited obligations of the Authority payable solely from the sources specified in the Indenture. Neither the State of California nor any public agency thereof (other than the Authority) nor any member of the Authority nor the Project Participant shall be obligated to pay the principal or Redemption Price (as defined in the Indenture) of, or interest on, the Bonds. Neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any member of the Authority or the Project Participant is pledged to the payment of the principal or Redemption Price of, or interest on, the Bonds. The Bonds shall not constitute a debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution or statutes of the State of California, and they shall not constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit.

2. Each Authorized Representative is hereby authorized (i) to execute and deliver a purchase contract for the Bonds (the "Purchase Contract"), between the Authority and J.P. Morgan Securities LLC, as representative of itself and PNC Capital Markets LLC (collectively, the "Underwriters"), and (ii) to negotiate the Underwriters' fee or discount relating to the Bonds. The purchase price at which the Bonds of each series is to be sold to the Underwriters and the related Underwriters' fee or discount shall each be determined in accordance with this Resolution. Payment for the Bonds shall be pursuant to the terms and conditions set forth in the Purchase Contract executed pursuant to this Resolution. The form of Purchase Contract on file with an Assistant Secretary is hereby made a part of this Resolution as though set forth in full herein and the same is hereby approved.

3. Each Authorized Representative is hereby authorized to approve a Preliminary Official Statement relating to the Bonds in the form on file with an Assistant Secretary of the Authority (such approval to be conclusively evidenced by the delivery thereof) (the "Preliminary Official Statement"), and the Board of Directors hereby approves the use of the Preliminary Official Statement in connection with the offering and sale of the Bonds, with such additions

thereto and changes therein as are determined necessary or appropriate by any Authorized Representative to make such Preliminary Official Statement final as of its date for purposes of Rule 15c2-12 of the Securities and Exchange Commission (except for the omission of those items permitted to be omitted therefrom by said Rule). Each Authorized Representative is authorized to deem the Preliminary Official Statement to be final within the meaning of such Rule 15c2-12. The Board of Directors hereby further approves the use of any supplement or amendment to the Preliminary Official Statement that is necessary or appropriate so that, in the opinion of any Authorized Representative (after consultation with the Authority's Disclosure Counsel), such Preliminary Official Statement does not contain any untrue statement of a material fact and does not omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which such statements were made, not misleading. The Underwriters are hereby authorized to distribute (including by electronic delivery) the Preliminary Official Statement to potential purchasers of the Bonds.

4. Each Authorized Representative is hereby authorized to approve an Official Statement relating to the Bonds (such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof) (the "Official Statement"), and the Board of Directors hereby approves the use of the Official Statement in connection with the offering and sale of the Bonds. The Board of Directors hereby further approves the use of any supplement or amendment to such Official Statement that is necessary or appropriate so that, in the opinion of any Authorized Representative (after consultation with the Authority's Disclosure Counsel), such Official Statement does not include any untrue statement of a material fact and does not omit to state a material fact necessary to make the statements therein, in the light of the circumstances under which such statements were made, not misleading. Each Authorized Representative is hereby authorized to execute the Official Statement and any amendment or supplement thereto, in the name and on behalf of the Authority, and thereupon to cause such Official Statement and any such amendment or supplement to be delivered to the Underwriters. The Underwriters are hereby authorized to distribute the Official Statement and any such amendment or supplement thereto to the purchasers of the Bonds.

5. The refunding of all or a portion of the Refunded Bond as provided for in the Third Supplemental Indenture and the Indenture is hereby authorized and approved. Each Authorized Representative and each of the Secretary and any Assistant Secretary of the Authority are hereby authorized on behalf of the Authority to take such other action as any of them may deem necessary or appropriate to effectuate such refunding.

6. Each Authorized Representative is hereby authorized to determine, in connection with the execution and delivery of the Indenture, the Third Supplemental Indenture and the Purchase Contract and the sale of the Bonds and in consultation with the representative of LADWP on the Authority's Finance Committee, the following:

(i) the principal amount of the Bonds of each series, which Bonds in the aggregate shall not exceed $250,000,000 principal amount;

(ii) if less than all of the Refunded Bonds are to be refunded by the Bonds, the series, principal amounts and maturities of such bonds to be refunded;

(iii) any transfers required or permitted from any funds or accounts created under the Indenture in connection with the refunding of the Refunded Bonds;

(iv) the date or dates on which the Refunded Bonds shall be paid or redeemed;

(v) the interest rates of the Bonds, the true interest cost of which in the aggregate shall not exceed 5.50% per annum;

(vi) the maturity dates for the Bonds, with the final maturity thereof being no later than July 1, 2038;

(vii) the principal amount of each maturity of the Bonds and sinking fund installments (if any) for any term Bonds;

(viii) the purchase price of the Bonds;

(ix) the interest payment dates for the Bonds;

(x) the redemption terms (if any) and prices of the Bonds;

(xi) the terms and conditions for delivery of the Bonds;

(xii) the application of the proceeds of the Bonds;

(xiii) the initial escrow securities, if any, to be deposited in the Escrow Funds for the Refunded Bonds under the Third Supplemental Indenture; and

(xiv) such other matters as may be determined by the Finance Committee.

7. Each Authorized Representative, the Secretary, any Assistant Secretary and any other officer of the Authority is hereby authorized to take any and all actions which such person deems necessary or advisable in order to effect the registration or qualification (or exemption therefrom) of the Bonds, or any portion thereof, for issue, offer, sale or trade under the Blue Sky or securities laws of any of the states or other jurisdictions of the United States of America and in connection therewith to execute, acknowledge, verify, deliver, file or cause to be published any applications, reports, consents to service of process, appointments of attorneys to receive service of process and other papers and instruments which may be required under such laws, and to take any and all further actions which such person may deem necessary or advisable in order to maintain any such registration or qualification for as long as such person deems necessary or as required by law or by the Underwriters; and any such action previously taken is hereby ratified, confirmed and approved.

8. The Board hereby approves (i) the fee of PFM Financial Advisors LLC (the "Municipal Advisor"), as the municipal advisor of the Authority in connection with the sale and issuance of the Bonds, which fee shall not exceed $85,000, (ii) the fee of Norton Rose Fulbright US LLP, as Bond Counsel and Disclosure Counsel to the Authority in connection with the sale and issuance of the Bonds, which fee shall not exceed $175,000, and (iii) the fee of Nixon

Peabody LLP, as Special Tax Counsel to the Authority in connection with the sale and issuance of the Bonds, which fee shall not exceed $60,000.

9. U.S. Bank Trust Company, National Association is hereby appointed as the Trustee and Paying Agent under the Indenture, and as Escrow Agent for the Refunded Bonds under the Third Supplemental Indenture. Each Authorized Representative is hereby authorized to appoint from time to time any additional fiduciaries, depositaries or agents in connection with the Bonds or any portion thereof and to execute and deliver any and all agreements, documents and instruments necessary or advisable in connection with such appointment of U.S. Bank Trust Company, National Association and with any other such appointment.

10. The Third Supplemental Indenture and any resolution of this Board of Directors as to the provision of certain continuing disclosure information with respect to the Bonds are hereby designated as "Project Agreements" under the Indenture and the Power Sales Agreement (as defined in the Indenture).

11. The Executive Director of the Authority, in addition to the other offices or positions with the Authority he already holds, is hereby appointed as an Authorized Authority Representative under the Indenture for the purpose of taking any and all required or permitted actions in connection with the issuance and delivery of the Bonds.

12. Each Authorized Representative, the Secretary, any Assistant Secretary, and any other officer of the Authority is hereby authorized to execute and deliver any and all agreements, amendments, documents and instruments and to do and cause to be done any and all acts and things deemed necessary or advisable for carrying out and giving effect to the transactions contemplated by this Resolution (including, but not limited to, (i) providing for the giving of written directions and notices, and the securing of any necessary third party approvals in connection with the issuance of the Bonds, each as required by the Power Sales Agreement, the Indenture, the Third Supplemental Indenture, the Purchase Contract or any other documents referred to in this Resolution or related to the Bonds and (ii) making such changes to the agreements, documents and instruments referred to in this Resolution, and such changes or new agreements as shall be requested by any rating agency, the Underwriters, the Authority, LADWP or any other entity, if such changes are determined by any such officer or Authorized Representative to be necessary or advisable). Each reference in this Resolution to the President, any Vice President, the Executive Director, the Chief Financial and Administrative Officer, the Secretary, any Assistant Secretary or other officer shall refer to the person holding such office or position, as applicable, at the time a given action is taken and shall not be limited to the person holding such office or position at the time of the adoption of this Resolution. All actions heretofore taken by the officers, employees and agents of the Authority in furtherance of the transactions contemplated by this Resolution are hereby approved, ratified and confirmed.

13. The Board hereby approves the execution and delivery of all agreements, documents, certificates and instruments referred to herein with electronic signatures as may be permitted under the California Uniform Electronic Transaction Act and digital signatures as may be permitted under Section 16.5 of the California Government Code.

14. In compliance with California Government Code Section 5852.1, the Authority has obtained from the Municipal Advisor the required good faith estimates in connection with the Bonds required by such section, which estimates are disclosed and set forth on Exhibit A attached hereto.

15. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority this 18th day of April, 2024.

____
PRESIDENT
Southern California Public
Power Authority

ATTEST:

____
RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

EXHIBIT A

GOOD FAITH ESTIMATES
(UNDER SECTION 5821.1 OF THE CALIFORNIA GOVERNMENT CODE)

The good faith estimates set forth herein are provided with respect to the Bonds in compliance with Section 5852.1 of the California Government Code. Such good faith estimates have been provided to the Authority by PFM Financial Advisors LLC, as municipal advisor to the Authority (the "Municipal Advisor").

Principal Amount. The Municipal Advisor has informed the Authority that, based on the Authority's financing plan and current market conditions, its good faith estimate of the aggregate principal amount of the Bonds to be sold is $185,710,000 (the "Estimated Principal Amount").

True Interest Cost of the Bonds. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the Bonds is sold, and based on market interest rates and swap rates prevailing at the time of preparation of such estimate, its good faith estimate of the initial true interest cost in aggregate of the Bonds, which means the rate necessary to discount the amounts payable on the respective principal and interest payment dates to the purchase price received for the Bonds, is 2.78%. This estimate is based on an initial Finance Charge of the Bonds as described below.

Finance Charge of the Bonds. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the Bonds is sold, and based on market interest rates and swap rates prevailing at the time of preparation of such estimate, its good faith estimate of the finance charge for the Bonds, which means the sum of all fees and charges paid to third parties (or costs associated with the Bonds), is $964,275.

Amount of Proceeds to be Received. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the amount of proceeds expected to be received by the Authority for sale of the Bonds, less the finance charge of the Bonds, as estimated above, and any reserves or capitalized interest paid or funded with proceeds of the Bonds, is $215,171,649.

Total Payment Amount. The Municipal Advisor has informed the Authority that, assuming that the Estimated Principal Amount of the Bonds is sold, and based on market interest rates prevailing at the time of preparation of such estimate, its good faith estimate of the total payment amount, which means the sum total of all payments the Authority will make to pay debt service on the Bonds, plus the finance charge for the Bonds, as described above, not paid with the proceeds of the Bonds, calculated to the final maturity of the Bonds, is $263,633,705.

The foregoing estimates constitute good faith estimates only. The actual principal amount of the Bonds issued and sold, the true interest cost thereof, the finance charges thereof, the amount of proceeds received therefrom and total payment amount with respect thereto may differ from such good faith estimates due to (a) the actual date of the sale of the Bonds being different than the date assumed for purposes of such estimates, (b) the actual principal amount of Bonds sold being different from the Estimated Principal Amount, (c) the actual amortization of the Bonds being different than the amortization assumed for purposes of such estimates, (d) the actual market interest rates at the time of sale or remarketing of the Bonds being different than those estimated for purposes of such estimates, (e) other market conditions or (f) alterations in the Authority's financing plan, or a combination of such factors. The actual date of sale of the Bonds and the actual principal amount of Bonds sold will be determined by the Authority based on the amount of 2014 Bonds to be refunded and other factors. The actual interest rates borne by the Bonds will depend on, among other things, market interest rates at the time of sale or remarketing thereof. The actual amortization of the Bonds will also depend, in part, on market interest rates at the time of sale thereof. Market interest rates are affected by economic and other factors beyond the control of the Authority.

[Project Vote: LADWP]

RESOLUTION NO. 2024-017

RESOLUTION AS TO THE PROVISION OF CERTAIN CONTINUING DISCLOSURE INFORMATION WITH RESPECT TO APEX POWER PROJECT, REFUNDING REVENUE BONDS, 2024 SERIES A

WHEREAS, the Board of Directors of the Southern California Public Power Authority, a political subdivision of the State of California ("SCPPA"), has authorized the issuance of SCPPA's Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the "Bonds") and has authorized the execution by SCPPA of the Indenture of Trust, dated as of March 1, 2014, from SCPPA to U.S. Bank Trust Company, National Association, as successor trustee (as supplemented, the "Indenture"), relating to the Bonds; and

WHEREAS, the Board of Directors of SCPPA hereby finds and determines that it is necessary, in connection with the authorization and sale of the Bonds, that SCPPA adopt this resolution in order to assist the Participating Underwriters (such term, and all other capitalized terms used herein without definition, having the respective meanings assigned thereto in Section 1 hereof) in complying with the Rule;

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of SCPPA as follows:

1. Definitions. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Resolution unless otherwise defined in this Disclosure Resolution, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report provided by SCPPA pursuant to, and as described in, Sections 3 and 4 of this Disclosure Resolution.

"Audited Financial Statements" shall mean:

(a) with respect to SCPPA, SCPPA's audited financial statements for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time (or such other accounting principles as may be applicable to SCPPA in the future pursuant to applicable law); and

(b) with respect to LADWP (as defined in Section 2(b) hereof), the audited financial statements of LADWP's Power System for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time (or such other accounting principles as may be applicable to LADWP in the future pursuant to applicable law).

"Beneficial Owner" shall mean any person holding a beneficial ownership interest in Bonds through nominees or depositories (including any person holding such interest through the book-entry only system of The Depository Trust Company), together with any other person who is intended to be a beneficiary of this Disclosure Resolution under the Rule.

"Disclosure Resolution" shall mean this resolution, as the same may be amended or supplemented from time to time in accordance with the provisions hereof.

"Dissemination Agent" shall mean any person or entity appointed by SCPPA and which has entered into a written agreement with SCPPA pursuant to which such person or entity agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

"Final Official Statement" shall mean the Official Statement of SCPPA relating to the Bonds, as amended, supplemented or updated.

"Financial Obligation" shall have the meaning ascribed to it in the Rule, any other applicable federal securities laws and guidance provided by the SEC in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), any further amendments or written guidance provided by the SEC or its staff with respect to the amendments to the Rule effected by the 2018 Release.

"Listed Events" shall mean any of the events listed in Section 5(a) of this Disclosure Resolution.

"MSRB" shall mean the Municipal Securities Rulemaking Board established pursuant to Section 15B(b)(1) of the Securities Exchange Act of 1934 or any other entity designated or authorized by the SEC to receive reports pursuant to the Rule. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the Electronic Municipal Market Access (EMMA) website of the MSRB, currently located at http://emma.msrb.org.

"Participating Underwriters" shall mean any of the original underwriters of the Bonds (or the underwriter, if there is only one original underwriter) required to comply with the Rule in connection with the offering of the Bonds.

"Rule" shall mean Rule 15c2-12 adopted by the SEC under the Securities Exchange Act of 1934, as amended from time to time, together with all interpretive guidance or other official interpretations or explanations thereof that are promulgated by the SEC.

"SEC" shall mean the United States Securities and Exchange Commission.

2. Purpose of this Disclosure Resolution; Obligated Persons; Disclosure Resolution to Constitute a Contract.

(a) This Disclosure Resolution is adopted by SCPPA for the benefit of the Owners and Beneficial Owners of the Bonds and in order to assist the Participating Underwriter in complying with the Rule.

(b) SCPPA and the Department of Water and Power of The City of Los Angeles ("LADWP") each is hereby determined by SCPPA to be an "obligated person" within the meaning of the Rule (and are the only "obligated persons" within the meaning of the Rule for whom financial information or operating data are presented in the Final Official Statement). Each such person shall only be an "obligated person" if and for so long as such person is an "obligated person" within the meaning of the Rule.

(c) In consideration of the purchase and acceptance of any and all of the Bonds by those who shall hold the same or shall own beneficial ownership interests therein from time to time, this Disclosure Resolution shall be deemed to be and shall constitute a contract between SCPPA and the Owners and Beneficial Owners from time to time of the Bonds, and the covenants and agreements herein set forth to be performed on behalf of SCPPA shall be for the benefit of the Owners and Beneficial Owners of any and all of the Bonds.

3. Provision of Annual Reports.

(a) SCPPA hereby covenants and agrees that it shall, or shall cause the Dissemination Agent to, not later than six months after the end of each fiscal year of SCPPA (presently, by each December 31, each such date being referred to herein as a "Final Submission Date"), commencing with the report for fiscal year 2023-24, provide to the MSRB an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Resolution. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Resolution; provided that any Audited Financial Statements may be submitted separately from the balance of the Annual Report and later than the Final Submission Date if they are not available by that date. If the fiscal year for SCPPA or LADWP changes, SCPPA shall give notice of such change in the same manner as for a Listed Event under Section 5(c).

(b) Not later than ten (10) business days prior to each Final Submission Date (each such date being referred to herein as a "Preliminary Submission Date"), SCPPA shall provide the Annual Report to the Dissemination Agent, if any. If by a Preliminary Submission Date, the Dissemination Agent, if any, has not received a copy of the Annual Report, the Dissemination Agent shall contact SCPPA to determine if SCPPA is in compliance with subsection (a).

(c) If SCPPA or the Dissemination Agent (if any), as the case may be, has not provided any Annual Report to the MSRB by a Final Submission Date, SCPPA or the Dissemination Agent, as applicable, shall provide a notice to the MSRB in substantially the form attached hereto as Exhibit A.

(d) SCPPA (or, in the event that SCPPA shall appoint a Dissemination Agent hereunder, the Dissemination Agent) shall provide the Annual Report to the MSRB on or before the Final Submission Date. In addition, if SCPPA shall have appointed a Dissemination Agent hereunder, the Dissemination Agent shall file a report with SCPPA certifying that the Annual Report has been provided to the MSRB pursuant to this Disclosure Resolution and stating the date it was provided.

(e) Any Annual Report must be submitted in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

4. Content of Annual Reports. SCPPA's Annual Report shall contain or include by reference the following:

(a) If available at the time of filing of the Annual Report as provided herein, the Audited Financial Statements of SCPPA and LADWP for the most recently ended fiscal year. If any Audited Financial Statements are not available by the Final Submission Date, the Annual Report shall contain unaudited financial statements for SCPPA and LADWP, as applicable, in a format similar to the audited financial statements most recently prepared for such obligated person, and such Audited Financial Statements shall be filed in the same manner as the Annual Report when and if they become available.

(b) Updated versions of the type of information contained in the Final Official Statement relating to the following:

(i) the financial information and operating data included in the section entitled "THE APEX POWER PROJECT"; and

(ii) the debt service requirements contained in Appendix F to the Final Official Statement.

(c) Updated versions of the type of information for LADWP contained in Appendix A to the Final Official Statement relating to the following:

(i) the description of operations and the summary of operating results of LADWP's Power System; and

(ii) the summary of financial results of LADWP's Power System.

Any or all of the items listed above may be included by specific reference to other documents, including Annual Reports of SCPPA or LADWP or official statements relating to debt or other securities issues of SCPPA, LADWP or other entities, which have been submitted to the MSRB. If the document included by reference is a final official statement (as defined in the Rule), it must be available from the MSRB. SCPPA shall clearly identify each such other document so included by reference.

5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, SCPPA hereby covenants and agrees that it shall give, or cause to be given, notice of the occurrence of any of the following events with respect to the Bonds:

(i) principal or interest payment delinquencies;

(ii) non-payment related defaults, if material;

(iii) modifications to the rights of the Bondholders, if material;

(iv) optional, contingent or unscheduled calls, if any of the preceding are material, and tender offers;

(v) defeasances;

(vi) rating changes;

(vii) adverse tax opinions or the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds or other material events affecting the tax status of the Bonds;

(viii) unscheduled draws on debt service reserves reflecting financial difficulties;

(ix) unscheduled draws on credit enhancements reflecting financial difficulties;

(x) substitution of credit or liquidity providers or their failure to perform;

(xi) release, substitution or sale of property securing repayment of the Bonds, if material;

(xii) bankruptcy, insolvency, receivership or similar proceedings described below of SCPPA or LADWP;

(xiii) appointment of a successor or additional trustee or the change of name of a trustee, if material;

(xiv) the consummation of a merger, consolidation, or acquisition involving SCPPA or LADWP or the sale of all or substantially all of the assets of the Apex Power Project other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

(xv) incurrence of a Financial Obligation of SCPPA or LADWP, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of SCPPA or LADWP, any of which affects Holders of the Bonds, if material; or

(xvi) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of SCPPA or LADWP, any of which reflect financial difficulties.

(b) An event described in item (xii) above of Section 5(a) is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent, or similar officer for SCPPA or LADWP in a proceeding under the United States Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of said party, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement, or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of said party.

(c) SCPPA intends to comply with the provisions hereof for the Listed Events described in items (xv) and (xvi) of Section 5(a) above, and the definition of the "Financial Obligation" in Section 2, with reference to the Rule, any other applicable federal securities laws and guidance provided by the SEC in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), any further amendments or written guidance provided by the SEC or its staff with respect to the amendments to the Rule effected by the 2018 Release.

(d) SCPPA shall provide notice of an occurrence of a Listed Event to the MSRB in a timely manner but not more than ten (10) business days after the occurrence of the event. Any notice of Listed Event(s) must be submitted to the MSRB in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

6. Management's Discussion of Items Disclosed in Annual Reports or as Significant Events. If an item required to be disclosed in SCPPA's Annual Report under Section 4, or as a Listed Event under Section 5, would be misleading without discussion, SCPPA additionally covenants and agrees that it shall provide a statement clarifying the disclosure in order that the statement made will not be misleading in the light of the circumstances under which it is made.

7. Termination of Reporting Obligations. SCPPA's obligations under this Disclosure Resolution shall terminate upon the legal defeasance, prior redemption or payment in full of all of the

Bonds. In addition, in the event that the Rule shall be amended, modified or repealed such that compliance by SCPPA with its obligations under this Disclosure Resolution no longer shall be required in any or all respects, then SCPPA's obligations under this Disclosure Resolution shall terminate to a like extent. If either such termination occurs prior to the final maturity of the Bonds, SCPPA shall give notice of such termination in the same manner as for a Listed Event under Section 5(d).

8. Dissemination Agent. SCPPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Resolution, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent.

9. Amendment; Waiver.

(a) Notwithstanding any other provision of this Disclosure Resolution, SCPPA may, by resolution hereafter adopted, amend this Disclosure Resolution, and any provision of this Disclosure Resolution may be waived, provided that, in the opinion of nationally-recognized bond counsel, such amendment or waiver is permitted by the Rule.

(b) The Annual Report containing any modified operating data or financial information as a result of an amendment shall explain, to the extent required by the Rule, in narrative form, the reasons for the amendment and the impact of the change in the type of operating data or financial information being provided. If a change in accounting principles is included in any such modification, such Annual Report shall present, to the extent required by the Rule, a comparison between the financial statements or information prepared on the basis of the modified accounting principles and those prepared on the basis of the former accounting principles.

10. Additional Information. Nothing in this Disclosure Resolution shall be deemed to prevent SCPPA from disseminating, or require SCPPA to disseminate, any other information using the means of dissemination set forth in this Disclosure Resolution or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Resolution. If SCPPA chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Resolution, SCPPA shall have no obligation under this Disclosure Resolution to update such information or include it in any future Annual Report, notice of occurrence of a Listed Event or other materials disseminated hereunder.

11. Default.

(a) In the event of a failure of SCPPA to comply with any provision of this Disclosure Resolution, any Owner or Beneficial Owner of any Outstanding Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, for the equal benefit and protection of all Owners or Beneficial Owners similarly situated, to cause SCPPA to comply with its obligations under this Disclosure Resolution.

(b) Notwithstanding the foregoing, no Owner or Beneficial Owner of the Bonds shall have the right to challenge the content or adequacy of the information provided pursuant to Sections 3, 4 or 5 of this Disclosure Resolution by mandamus, specific performance or other equitable proceedings unless Owners or Beneficial Owners of Bonds representing at least 25% in aggregate principal amount of the Outstanding affected Bonds shall join in such proceedings.

(c) A default under this Disclosure Resolution shall not be deemed an Event of Default under the Indenture, and the sole remedies under this Disclosure Resolution in the event of any failure of SCPPA to comply with this Disclosure Resolution shall be those described in subsection (a) above.

(d) Under no circumstances shall any person or entity be entitled to recover monetary damages hereunder in the event of any failure of SCPPA to comply with this Disclosure Resolution.

12. Duties, Immunities and Liabilities of Dissemination Agent. Any Dissemination Agent appointed hereunder shall have only such duties as are specifically set forth in this Disclosure Resolution, and shall have such rights, immunities and liabilities as shall be set forth in the written agreement between SCPPA and such Dissemination Agent pursuant to which such Dissemination Agent agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

13. Beneficiaries. This Disclosure Resolution shall inure solely to the benefit of SCPPA, the Dissemination Agent, if any, and the Owners and Beneficial Owners from time to time of the Bonds, and, subject to Section 2(a) hereof, shall create no rights in any other person or entity.

14. Governing Law. This Disclosure Resolution shall be deemed to be a contract made under the Rule and the laws of the State of California, and for all purposes shall be construed and interpreted in accordance with, and its validity governed by, the Rule and the laws of the State of California, without regard to principles of conflicts of law.

15. Effective Date. This Disclosure Resolution shall become effective upon the date of authentication and delivery of the Bonds.

THE FOREGOING RESOLUTION is approved and adopted by SCPPA this 18th day of April, 2024.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

____
PRESIDENT
Southern California Public
Power Authority

ATTEST:

____
ASSISTANT SECRETARY
Southern California Public
Power Authority

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Southern California Public Power Authority
Name of Bond Issue:	$____________ Apex Power Project Refunding Revenue Bonds, 2024 Series A
Date of Issuance:	_________, 2024

NOTICE IS HEREBY GIVEN that Southern California Public Power Authority ("SCPPA") has not provided an Annual Report with respect to the above-named Bonds as required by Section 3(a) of Resolution No. 2024-_____, adopted by the Board of Directors of SCPPA on April 18, 2024, relating to the above-named Bonds. SCPPA [has advised the undersigned that SCPPA] anticipates that the Annual Report will be filed by __________________.]

Dated: _______________

[SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY]
[__________________, as Dissemination Agent on
behalf of Southern California Public Power Authority]

[cc: Southern California Public
Power Authority]

DRAFT OF
04/__/24

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

To

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION,
as Trustee

____

THIRD SUPPLEMENTAL INDENTURE OF TRUST

____

Dated as of __________, 2024

$___________
Apex Power Project, Revenue Refunding Bonds, 2024 Series A

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THIRD SUPPLEMENTAL INDENTURE OF TRUST

THIS THIRD SUPPLEMENTAL INDENTURE OF TRUST (the "Third Supplemental Indenture"), dated as of __________, 2024, is from Southern California Public Power Authority, established under the laws of the State of California (the "Authority"), to U.S. Bank Trust Company, National Association, a national banking association, as successor trustee (the "Trustee").

W I T N E S S E T H :

WHEREAS, the Authority has entered into an Indenture of Trust, dated as of March 1, 2014 (the "Original Indenture" and, as supplemented and amended, including as supplemented by this Third Supplemental Indenture, the "Indenture"), from the Authority to the Trustee to provide for the securing of Bonds;

WHEREAS, the Indenture provides that the Authority may issue one or more Series of Bonds from time to time for the purpose of paying (or refinancing) all or a portion of the Cost of Acquisition of the Project or the costs of any Capital Improvements with respect to the Project, and other costs relating thereto, as authorized by a Supplemental Indenture;

WHEREAS, the Authority has heretofore issued its Apex Power Project, Revenue Bonds, 2014 Series A (the "2014 Series A Bonds") in the aggregate principal amount of $151,880,000, all of which principal amount is currently outstanding, and its Apex Power Project, Revenue Bonds, 2014 Series B (Federally Taxable) (the "2014 Series B Bonds") in the aggregate principal amount of $166,980,000, of which $78,155,000 in aggregate principal amount is currently outstanding;

WHEREAS, the Authority desires to issue its Apex Power Project, Revenue Refunding Bonds, 2024 Series A (the "2024 Series A Bonds") in the aggregate principal amount of $[________], pursuant to this Third Supplemental Indenture, in order to provide funds to (i) make a deposit to the Escrow Fund established hereunder to refund the outstanding 2014 Series A Bonds and (ii) pay the costs of issuance in connection with the delivery of the 2024 Series A Bonds;

WHEREAS, the 2024 Series A Bonds will be secured under the Indenture; and

WHEREAS, all acts and things have been done and performed that are necessary to make the 2024 Series A Bonds, when executed and issued by the Authority, authenticated by the Trustee and delivered, the valid and binding legal obligations of the Authority in accordance with their terms and to make this Third Supplemental Indenture a valid and binding agreement for the security of the 2024 Series A Bonds authenticated and delivered under the Indenture;

NOW, THEREFORE, THIS THIRD SUPPLEMENTAL INDENTURE WITNESSETH:

That, in consideration of the premises, the acceptance by the Trustee of the trusts hereby created and originally created by the Original Indenture, the mutual covenants herein contained and the purchase and acceptance of the 2024 Series A Bonds issued hereunder by the Owners thereof, and for other valuable consideration, the receipt of which is hereby acknowledged, and in order to secure the payment of the principal or Redemption Price (if any) of, and interest on, the 2024 Series A Bonds issued hereunder according to their tenor and effect, and the performance and observance by the Authority of all the covenants and conditions contained herein and in the Indenture on its part to be performed, it is agreed by and between the Authority and the Trustee as follows:

ARTICLE I

AUTHORITY AND DEFINITIONS

101. Authority for this Third Supplemental Indenture. This Third Supplemental Indenture is a Supplemental Indenture executed pursuant to the provisions of the Act and in accordance with Article II and Article X of the Original Indenture.

102. Definitions.

(1) Except as provided by this Third Supplemental Indenture, all terms that are defined in the Original Indenture shall have the same meanings in this Third Supplemental Indenture as such terms are given in the Original Indenture.

(2) In this Third Supplemental Indenture:

Escrow Fund shall mean the Apex Power Project, Revenue Bonds, 2014 Series A and 2014 Series B Escrow Fund established pursuant to Section 401 of this Third Supplemental Indenture.

Interest Payment Date shall mean, with respect to the 2024 Series A Bonds, January 1 and July 1 of each year, commencing [July 1, 2024], as specified in Section 203 of this Third Supplemental Indenture.

Refunded Bonds shall mean the outstanding 2014 Series A Bonds and the outstanding 2014 Series B Bonds.

2024 Series A Bonds shall mean the Authority's Apex Power Project, Revenue Refunding Bonds, 2024 Series A, authorized by Article II of this Third Supplemental Indenture.

2024 Series A Costs of Issuance Account shall mean the Apex Power Project, Revenue Refunding Bonds, 2024 Series A, Costs of Issuance Account established pursuant to Section 208 of this Third Supplemental Indenture..

ARTICLE II

AUTHORIZATION OF 2024 SERIES A BONDS

201. Principal Amount, Designation and Series. Pursuant to the provisions of the Indenture, a Series of Bonds entitled to the benefit, protection and security of such provisions is hereby authorized in the aggregate principal amount of $____________. Such Bonds shall be designated as, and shall be distinguished from the Bonds of all other Series by the title, "Apex Power Project, Revenue Refunding Bonds, 2024 Series A," and shall be referred to herein as the "2024 Series A Bonds."

[Pursuant to Section 202 of the Original Indenture, the 2024 Series A Bonds are hereby determined to be Participating Bonds pursuant to the Original Indenture and shall be secured by the Participating Bonds Debt Service Reserve Account in accordance with the provisions of the Original Indenture.]

202. Purpose. The 2024 Series A Bonds are issued to provide funds to (i) make a deposit to the Escrow Fund established hereunder to refund all of the outstanding Refunded Bonds and (ii) pay the costs of issuance relating to the 2024 Series A Bonds. Such purposes constitute purposes described in Section 203 of the Original Indenture.

203. Date, Maturities and Interest. The 2024 Series A Bonds shall be dated their date of delivery. Interest on the 2024 Series A Bonds shall be payable on [July 1, 2024] and semiannually thereafter on each January 1 and July 1, which dates are hereby specified as the Interest Payment Dates for the 2024 Series A Bonds pursuant to the provisions of the Original Indenture. The 2024 Series A Bonds shall bear interest from the Interest Payment Date next preceding the date of authentication thereof unless such 2024 Series A Bonds are authenticated on an Interest Payment Date, in which event from such Interest Payment Date; provided, however, that if the date of authentication shall be prior to the first Interest Payment Date for the 2024 Series A Bonds, such 2024 Series A Bonds shall bear interest from their date of delivery; and provided, further, that if, on the date of authentication thereof, interest on the 2024 Series A Bonds shall be in default as shown by the records of the Trustee, such 2024 Series A Bonds shall bear interest from the Interest Payment Date to which interest has been paid or duly provided for in full. Interest on the 2024 Series A Bonds shall be calculated on the basis of a 360-day year comprised of twelve 30-day months.

The 2024 Series A Bonds shall mature on July 1 in the years and in the principal amounts, and shall bear interest payable semiannually on each Interest Payment Date therefor, at the respective interest rates and yields per annum, shown below:

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	CUSIP

204. Registered Form, Denomination, Numbers and Letters. The 2024 Series A Bonds shall be issued in fully registered form in the denominations of $5,000 or any integral multiple of $5,000. The 2024 Series A Bonds shall be registered in book-entry format as provided in Section 309 of the Original Indenture. The 2024 Series A Bonds initially issued shall be numbered in a manner determined by the Trustee so as to be distinguished from every other such 2024 Series A Bond, with each such number designation preceded by the letter "R."

205. Place of Payment and Paying Agents. Subject to Section 309 of the Original Indenture, the principal and Redemption Price (if any) of the 2024 Series A Bonds shall be payable upon presentation and surrender at the corporate trust office of U.S. Bank Trust Company, National Association, St. Paul, Minnesota, or such other office designated by the Trustee, and U.S. Bank Trust Company, National Association is hereby appointed as Paying Agent for the 2024 Series A Bonds. The principal and Redemption Price (if any) of the 2024 Series A Bonds shall also be payable at any other place that may be provided for such payment by the appointment of any other Paying Agent or Paying Agents as permitted by the Indenture. Interest on the 2024 Series A Bonds shall be payable by check of the Trustee mailed by first-class mail to the registered owners shown on the registration books of the Authority kept by the Bond Registrar as of the close of business on the record date (established as provided below) immediately preceding each Interest Payment Date, except that in the case of an Owner of $1,000,000 or more in aggregate principal amount of 2024 Series A Bonds, upon written request of such Owner to the Trustee received at least ten (10) days prior to the applicable record date, specifying the account or accounts to which such payment shall be made (which request shall remain in effect until revoked or reversed by such Owner in a subsequent writing delivered to the Trustee), such interest shall be paid in immediately available funds by wire transfer to such account or accounts on each such following Interest Payment Date. As provided in subsection 4 of Section 301 of the Original Indenture, the record dates for the payment of interest on the 2024 Series A Bonds are hereby established as the fifteenth (15^{th}) day of the calendar month immediately preceding each Interest Payment Date.

206. Redemption Prices and Terms.

(1) Optional Redemption. The 2024 Series A Bonds are subject to redemption prior to maturity, at the option of the Authority, from any source of available funds, in whole or in part (and, if in part, from such maturities as the Authority shall direct), on any date on or after July 1, 2034, at a Redemption Price equal to the principal amount of the 2024 Series A Bonds, or portions thereof, to be redeemed, without premium, in each case together with accrued interest to the redemption date.

(2) Selection of 2024 Series A Bonds for Redemption. Whenever by the terms of the Indenture, 2024 Series A Bonds are to be redeemed at the direction of the Authority, the Authority shall select the maturity or maturities of the 2024 Series A Bonds to be redeemed. If less than all of the 2024 Series A Bonds of a maturity are called for prior redemption, the particular 2024 Series A Bonds or portions of such maturity to be redeemed shall be selected by lot, subject to the authorized denominations applicable to the 2024 Series A Bonds. The Trustee shall promptly notify the Authority in writing of the 2024 Series A Bonds so selected for redemption.

207. [Reserved.]

208. Application of Proceeds of 2024 Series A Bonds; Deposit of Moneys. In accordance with subsection 2 of Section 203 of the Original Indenture, the proceeds of the 2024 Series A Bonds in the amount of $____________ (representing the principal amount of the 2024

Series A Bonds of $____________ plus original issue premium of $____________ less $___________ of underwriters' discount) shall be applied simultaneously with the delivery of the 2024 Series A Bonds, as follows:

(i) There shall be deposited in the Escrow Fund the amount of $___________, which[, together with the amount of $___________ to be transferred therein pursuant to Section ____ hereof,] shall be applied as set forth in Article IV hereof to refund the outstanding Refunded Bonds; and

(ii) The remaining balance of proceeds of the 2024 Series A Bonds (*i.e.*, $___________) shall be deposited in the 2024 Series A Costs of Issuance Account, which is hereby established with the Trustee as an Account within the Project Fund, to be used to pay costs of issuance relating to the 2024 Series A Bonds.

209. Investment Income. Interest and other investment income (net of that which (i) represents a return of accrued interest paid in connection with the purchase of any investment and (ii) is required to offset the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in the Funds and Accounts (other than any Decommissioning Fund and the Project Fund) established under the Indenture, to the extent resulting in a balance that is in excess of any requirement for such Fund or Account, shall be paid into the Revenue Fund.

210. Form of 2024 Series A Bonds; Trustee's Certificate of Authentication; Execution. Subject to the provisions of the Indenture, the form of the 2024 Series A Bonds and the Trustee's certificate of authentication shall be substantially of the tenor set forth in Article XIII of the Original Indenture. The 2024 Series A Bonds may be executed by manual or facsimile signature of the President or Vice President of the Authority and the seal may be attested by the manual or facsimile signature of the Secretary or an Assistant Secretary of the Authority.

ARTICLE III

TAX COVENANTS

301. Tax Covenants. The Authority shall not take any action or omit to take any action that, if taken or omitted, respectively, would adversely affect the excludability of interest on any 2024 Series A Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes and, furtherance thereof, shall comply with the Tax Certificate as to Arbitrage and the Provisions of Sections 141-150 of the Internal Revenue Code of 1986 executed and delivered by the Authority on the date of delivery of the 2024 Series A Bonds, as the same may be supplemented or amended, including any and all exhibits attached thereto. The Authority and the Trustee shall execute such amendments hereof and supplements hereto (and shall comply with the provisions thereof) as are, in the Opinion of Bond Counsel, necessary to preserve such exclusion. The Authority shall comply with this covenant at all times prior to the last maturity of 2024 Series A Bonds or, if necessary, until no longer required to to maintain the excludability of interest on any 2024 Series A Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes, unless to comply with such covenant, either generally or to the extent stated therein, shall not adversely affect the excludability of interest on any 2024 Series A Bond from the gross income, as defined in section 61 of the Code, of the owner thereof for federal income tax purposes, and thereafter such covenant shall no longer be binding upon the Authority, generally or to such extent as the case may be.

ARTICLE IV

ESCROW FUND

401. Establishment of the Escrow Fund. There is hereby created and established with the Trustee, as Escrow Agent, a special and irrevocable trust fund under the Indenture designated the Apex Power Project, Revenue Bonds, 2014 Series A and 2014 Series B Escrow Fund (the "Escrow Fund") to be held by the Trustee separate and apart from all other funds of the Authority or the Trustee. Amounts on deposit in the Escrow Fund shall irrevocably be applied solely for the purposes and on the terms and conditions set forth in this Third Supplemental Indenture. The Trustee shall have no claim against, or right to payment from, any moneys or investments in the Escrow Fund.

402. Use and Investment of Moneys on Deposit in the Escrow Fund.

(1) The Trustee (a) acknowledges receipt of the portion of the proceeds of the 2024 Series A Bonds to be deposited in the Escrow Fund as provided in Section 208 hereof and (b) agrees immediately to invest such amounts in the Escrow Securities, if any, described in Exhibit A hereto (all of which Escrow Securities are non-callable, direct obligations of, or obligations fully and unconditionally guaranteed as to the timely payment of principal and interest by, the United States of America) and to deposit or cause to be deposited such Escrow Securities, if any, in the Escrow Fund.

(2) The Trustee acknowledges investment in and receipt of the Escrow Securities described in Exhibit A hereto, if any.

(3) Subject to Section 404 and Section 405 hereof, any moneys in the Escrow Fund not invested pursuant to this Section 402 shall be held uninvested as cash.

403. Payment and Redemption of Refunded Bonds.

(1) Subject to reinvestment permitted or required hereunder, as the principal of any Escrow Securities shall mature and be paid, and the investment income and earnings thereon are paid, the Trustee shall transfer from the Escrow Fund to the paying agent for the Refunded Bonds amounts sufficient to pay on July 1, 2024 the principal of the Refunded Bonds maturing on July 1, 2024, together with accrued interest to such date, and to pay on [July 1], 2024 the redemption price of the Refunded Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, together with accrued interest to the redemption date. Any moneys remaining in the 2024 Series A Escrow Fund after payment of the Refunded Bonds in full shall be deposited by the Trustee into the Revenue Fund to be applied as provided in the Original Indenture.

(2) The Authority hereby irrevocably instructs the Trustee to mail a notice substantially in the form of Exhibit C hereto to the registered owners of the Refunded Bonds and each Rating

Agency that a deposit has been made with the Trustee as herein provided and that the Refunded Bonds are deemed to have been paid in accordance with the Original Indenture, moneys from such deposit are to be available for payment on July 1, 2024 of the principal of the Refunded Bonds maturing on July 1, 2024, together with accrued interest to such date, and to pay on [July 1], 2024 the redemption price of the Refunded Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, together with accrued interest to the redemption date, all in accordance with subsection 2 of Section 1201 of the Original Indenture.

(3) The Trustee hereby confirms that it will take all the actions required to be taken by it under the Indenture in order to effectuate the payment and redemption of the Refunded Bonds in accordance with this Section 603 and the Original Indenture.

(4) One year after the date when the Refunded Bonds have become due and payable, all remaining moneys and Escrow Securities, if any, held by the Trustee pursuant to Section 602 hereof with respect to such Refunded Bonds shall be paid to the Authority as its absolute property, free from trust; provided, however, that the Trustee shall first publish any notice required by the Indenture that said moneys remain unclaimed if such notice is required.

(5) The Owners of the Refunded Bonds shall have an exclusive lien on the moneys and any Escrow Securities in the Escrow Fund until such moneys and Escrow Securities are used and applied as provided in this Third Supplemental Indenture.

404. Reinvestment. Except as provided in Section 602, Section 603 and Section 605 hereof, the Trustee shall have no power or duty to invest any funds held in the 2014 Series A Escrow Fund or to sell, transfer or otherwise dispose of the moneys or Escrow Securities held hereunder.

405. Substitution of Escrow Securities.

(1) the conditions set forth in Exhibit B attached hereto are satisfied in the case of a transaction referred to in said Exhibit B; or

(2) (i) the substitution of such other Escrow Securities for the Escrow Securities then held in the Escrow Fund, if any, occurs simultaneously; and

(ii) the amounts of and dates on which the anticipated transfers from the Escrow Fund to the paying agent for the payment of the Refunded Bonds and the interest thereon will not be diminished or postponed thereby;

(3) the Trustee shall receive the unqualified opinion of nationally recognized municipal bond attorneys to the effect that (A) such disposition and substitution would not cause any of the Refunded Bonds or the 2024 Series A Bonds to be an “arbitrage bond” within the meaning of section 148 of the Code and the regulations thereunder in effect on the date of such disposition and substitution and applicable to obligations issued on the respective issue dates of the Refunded Bonds and the 2024 Series A Bonds and that the conditions of this Section 605 as to the disposition and substitution have been satisfied and (B) the Authority has the right and power to effect such disposition and substitution; and

(4) the Trustee shall receive from an independent certified public accountant or independent arbitrage rebate specialist a certification that, immediately after such transaction, the principal of and interest on the securities in the Escrow Fund, if any, will, together with other moneys available in the Escrow Fund for such purpose, be sufficient to pay, when due as provided in subsection (1) of Section 603 hereof, the principal of and interest on the Refunded Bonds and interest thereon. Any cash received from the disposition and substitution of Escrow Securities pursuant to this Section 605 to the extent such cash will not be required, in accordance with the Indenture and the then applicable verification report of an independent certified public accountant or independent arbitrage rebate consultant, at any time for the payment when due as provided in subsection (1) of Section 603 hereof of the principal of and interest on the Refunded Bonds, shall be paid to the Authority as received by the Trustee free and clear of any trust, lien, pledge or assignment securing the Refunded Bonds or otherwise existing under the Indenture.

406. Termination of Obligations. As provided in subsection 2 of Section 1201 of the Original Indenture, upon the transfer of the moneys described in Section 208 hereof to the Escrow Agent, the deposit of such moneys in the Escrow Fund and the purchase of Escrow Securities, if any, as provided in Section 602 hereof, except for the rights of the Owners of the Refunded Bonds to payments from the Escrow Fund, the Owners of the Refunded Bonds shall cease to be entitled to any lien, benefit or security under the Indenture, and all covenants, agreements and other obligations of the Authority to the Owners of the Refunded Bonds shall thereupon cease, terminate and become void and be discharged and satisfied. Notwithstanding the foregoing, the Trustee shall replace Refunded Bonds which become mutilated, lost, stolen or destroyed and shall register the transfer of and exchange Refunded Bonds all in the manner and upon the terms and conditions provided in the Indenture until the Refunded Bonds have been paid.

407. Amendment of Article IV. Notwithstanding any provision of the Indenture to the contrary, this Article IV and those portions of Articles I, II and V which pertain to the Escrow Fund shall not be amended or supplemented without the consent of the Owners of 100% in principal amount of the Refunded Bonds which remain unpaid (without reference to subsection 2 of Section 1201 of the Original Indenture) at the time such consent is given except to (a) clarify an ambiguity (provided the clarification of such ambiguity does not materially adversely affect the interest of the Owners of the Refunded Bonds in the Escrow Fund) or (b) strengthen the security for the Owners of the Refunded Bonds in the Escrow Fund. Notwithstanding any provision of the Indenture to the contrary, no provision of this Article IV may be amended or supplemented in any manner if such amendment or supplement would materially adversely affect the interests of the Owners of the 2024 Series A Bonds.

ARTICLE V

MISCELLANEOUS

501. Indenture to Remain in Effect. Except as supplemented by this Third Supplemental Indenture, the Original Indenture shall remain in full force and effect.

502. Counterparts. This Third Supplemental Indenture may be executed in any number of counterparts, each of which, when so executed and delivered, shall be an original; such counterparts shall together constitute but one and the same instrument.

503. Performance of Duties. The Trustee, including in its capacity as Paying Agent hereunder, agrees to perform its duties set forth herein.

504. Severability. If any one or more of the covenants or agreements provided in this Third Supplemental Indenture to be performed on the part of the Authority or the Trustee, including in its capacity as Paying Agent hereunder, should be determined by a court of competent jurisdiction to be contrary to law, such covenants or agreements shall be null and void and shall be deemed separate from the remaining covenants and agreements contained herein and shall in no way affect the validity of the remaining provisions of this Third Supplemental Indenture.

505. Assignment. The rights, obligations and duties of the Trustee set forth herein, including its rights, obligations and duties as Paying Agent, shall not be assigned by the Trustee or any successor thereto without the prior written consent of the Authority.

506. Effective Date. This Third Supplemental Indenture shall become effective at such time as this Third Supplemental Indenture shall be executed and delivered by the Authority and the Trustee.

IN WITNESS WHEREOF, Southern California Public Power Authority has caused this Third Supplemental Indenture of Trust to be signed in its name and on its behalf by its President (or Vice President), and its seal to be hereunto affixed and attested by its Secretary (or an Assistant Secretary), thereunto duly authorized, and to evidence its acceptance of the trusts hereby created, the Trustee has caused these presents to be signed in its name and on its behalf by its duly authorized officer.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By ____________________________________
President

Attest ________________________________
Assistant Secretary

U.S. BANK TRUST COMPANY, NATIONAL
ASSOCIATION,
as Trustee

By ____________________________________
Vice President

EXHIBIT A

ESCROW SECURITIES

UNITED STATES TREASURY SECURITIES – STATE AND LOCAL GOVERNMENT SERIES

Description	Maturity	Par Amount	Coupon Rate

Cash deposit: $____________

Total: $____________

EXHIBIT B

LETTER FOR SUBSTITUTION OF ESCROW SECURITIES

[Authority Letterhead]

U.S. Bank Trust Company, National Association
633 W. Fifth Street, 24th Floor
Los Angeles, California 90071

Ladies and Gentlemen:

In your capacity as Trustee under the Indenture of Trust dated as of March 1, 2014, as supplemented and amended, including as supplemented and amended by the Third Supplemental Indenture of Trust, dated as of ________ 1, 2024 (the "Third Supplemental Indenture"), from Southern California Public Power Authority (the "Authority") to you, you have acquired for the account of the Authority and are holding the Escrow Securities listed in Column A of Annex A hereto (the "Column A Securities"). You are hereby instructed to deliver without further direction from the Authority, the Column A Securities to ________________________ against delivery to you by ___________________________ of the corresponding Escrow Securities listed in Column B of Annex A hereto (the "Column B Securities"); provided, however, that in connection with but prior to any such delivery, you shall receive documentation evidencing satisfaction of the requirement set forth in subsection (4) of Section 405 of the Third Supplemental Indenture, which documentation may be in the form of a letter from ______________________ confirming their opinions and conclusions as to the sufficiency of payment set forth in their report to the Authority, dated ___________, 2024, reflecting such exchange of Escrow Securities.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By: ___________________________________

Title: ___________________________________

Receipt of the instructions set forth above is hereby acknowledged.

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION,
as Trustee

By: _________________________________
Title: _________________________________
Date: _________________________________

Annex A

Column A Securities			Column B Securities		
Maturity	Coupon Rate	Par Amount	Maturity	Coupon Rate	Par Amount

EXHIBIT C

NOTICE OF REDEMPTION AND DEFEASANCE

**SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APEX POWER PROJECT, REVENUE BONDS,
2014 SERIES A (TAX-EXEMPT)**

CUSIP*	Maturity Date	Interest Rate	Principal Amount
84247PHF1	July 1, 2030	5.000%	$10,015,000
84247PHG9	July 1, 2031	5.000	14,855,000
84247PHH7	July 1, 2032	5.000	15,600,000
84247PHJ3	July 1, 2033	5.000	16,380,000
84247PHK0	July 1, 2034	5.000	17,200,000
84247PHL8	July 1, 2035	5.000	18,055,000
84247PHM6	July 1, 2036	5.000	18,960,000
84247PHN4	July 1, 2037	5.000	19,910,000
84247PHP9	July 1, 2038	5.000	20,905,000

**SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APEX POWER PROJECT, REVENUE BONDS,
2014 SERIES B (FEDERALLY TAXABLE)**

CUSIP†	Maturity Date	Interest Rate	Principal Amount
84247PHZ7	July 1, 2024	3.608%	$11,205,000
84247PJA0	July 1, 2025	3.758	11,610,000
84247PJB8	July 1, 2026	3.938	12,045,000
84247PJC6	July 1, 2027	4.108	12,520,000
84247PJD4	July 1, 2028	4.208	13,035,000
84247PJE2	July 1, 2029	4.308	13,585,000
84247PJF9	July 1, 2030	4.408	4,155,000

NOTICE IS HEREBY GIVEN to the owners of the above-mentioned bonds (the “Bonds”) issued by the Southern California Public Power Authority (the “Authority”) that the Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, have been called for redemption, prior to maturity, on [July 1], 2024 (the “Redemption Date”), at a redemption price of one hundred percent (100%) of the principal amount thereof (the “Redemption Price”), in each case plus accrued interest to the Redemption Date. From and after the Redemption Date, interest on such Bonds shall cease to accrue and be payable.

Payment of the Redemption Price on such Bonds called for redemption will be paid only upon presentation and surrender thereof in the following manner:

If by Hand or Overnight Mail:
U.S. Bank Trust Company, National Association
Global Corporate Trust
111 Fillmore Ave E.
St. Paul, MN 55107
1-800-934-6802

Bondholders presenting their Bonds in person for same day payment **must** surrender their Bond(s) by 1:00 p.m. on the Redemption Date, and a check will be available for pick up after 2:00 p.m. Checks not picked up by 4:30 p.m. will be mailed out to the Bondholder via first class mail. If payment of the Redemption Price is to be made to the registered owner of the Bond, you are not required to endorse the Bond to collect the redemption price.

The Authority has deposited with U.S. Bank Trust Company, National Association, the trustee for the Bonds, cash and obligations of or unconditionally guaranteed by the United States of America, the principal of and interest on which when due will provide money sufficient to pay on July 1, 2024 the principal of the Bonds maturing on July 1, 2024, together with accrued interest to such date, and to pay on [July 1], 2024 the Redemption Price of the Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, together with accrued interest to the redemption date. The principal, interest and Redemption Price payable on the Bonds shall be paid only from moneys available as aforesaid. As a result of such deposit, the Bonds are deemed to have been paid in accordance with the applicable provisions of the Authority's Indenture pursuant to which such bonds were issued.

IMPORTANT NOTICE: Federal law requires the Trustee to withhold taxes at the applicable rate from the payment if an IRS Form W-9 or applicable IRS Form W-8 is not provided. Please visit www.irs.gov for additional information on the tax forms and instructions.

**The Authority and the Trustee shall not be held responsible for the selection or use of the CUSIP numbers, nor is any representation made as to its correctness indicated in this Notice or as printed on any Bond. It is included solely for the convenience of the Bondholders.*

By U.S. Bank Trust Company, National Association,
as Trustee

DATED this ____th day of June, 2024.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

$______________
Apex Power Project,
Refunding Revenue Bonds, 2024 Series A

PURCHASE CONTRACT

_________, 2024

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY
1160 Nicole Court
Glendora, California 91740
Attention: Executive Director

Ladies and Gentlemen:

The undersigned, J.P. Morgan Securities LLC as representative (the “Representative”) of itself and PNC Capital Markets LLC (the “Underwriters”), offers to enter into the following agreement (this “Purchase Contract”) with Southern California Public Power Authority (“SCPPA”) which, upon SCPPA’s acceptance of this offer, will be binding upon SCPPA and upon the Underwriters. This offer is made subject to SCPPA’s written acceptance hereof on or before 5:00 P.M., Los Angeles time, on the date hereof and, if not so accepted, will be subject to withdrawal by the Representative upon written notice (by facsimile transmission or otherwise) delivered to SCPPA by the Representative at any time prior to the acceptance hereof by SCPPA. Terms used herein and not defined shall have the respective meanings assigned to them in the Official Statement (as defined in Section 3). The Representative represents that it has been duly authorized by the other Underwriters to act hereunder on their behalf and shall have full authority to take such action as it may deem advisable in respect of all matters pertaining to this Purchase Contract and that the Representative has been duly authorized to execute this Purchase Contract. Any action taken under this Purchase Contract by the Representative will be binding upon all the Underwriters.

1. Purchase and Sale. Upon the terms and conditions and upon the basis of the representations, warranties and agreements set forth herein, the Underwriters hereby agree, jointly and severally, to purchase from SCPPA, and SCPPA hereby agrees to sell and deliver to or for the account of the Underwriters, $______________ aggregate principal amount of Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the “Bonds”). The Bonds shall be dated their date of delivery and shall mature on the dates and in the principal amounts and bear interest at the rates (payable on January 1 and July 1 in each year, commencing _____ 1, 202[4][5]), as set forth on Schedule I hereto. The Bonds are subject to redemption prior to their maturity as set forth in the Indenture. The purchase price for the Bonds shall be $_______, which is equal to the par amount of the Bonds, [plus][less][net] original issue [premium][discount] of $_________, and less Underwriters’ discount of $_____.

2. The Bonds. The Bonds shall be described in, and shall be issued and secured pursuant to, the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the "Act"), and Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of California, and pursuant to an Indenture of Trust, dated as of March 1, 2014 (the "Indenture of Trust"), from SCPPA to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"), as supplemented and amended, including as supplemented and amended by the Third Supplemental Indenture of Trust, dated as of [_______ 1, 2024] (the "Third Supplemental Indenture"), from SCPPA to the Trustee. The Indenture of Trust, as so supplemented and amended, is herein referred to as the "Indenture." The Bonds shall be payable from the Revenues and certain other funds, as provided in the Indenture, and shall be as described in the Official Statement. SCPPA shall provide annual updates of certain financial information and operating data contained or incorporated by reference in the Official Statement and notice of certain specified events with respect to the Bonds pursuant to that certain Continuing Disclosure Resolution relating to the Bonds (the "Disclosure Resolution") adopted by SCPPA's Board of Directors on _________, 2024, to be effective upon the delivery of the Bonds.

The Bonds are being issued to: (i) refund SCPPA's outstanding Apex Power Project, Revenue Bonds, Series 2014 A and Apex Power Project, Revenue Bonds, Series 2014 B (Federally Taxable) and (ii) pay costs of issuance relating to the Bonds.

3. Delivery of Official Statement. SCPPA has heretofore delivered to the Underwriters a Preliminary Official Statement, dated ___________, 2024, relating to the Bonds (as amended or supplemented, the "Preliminary Official Statement"), that SCPPA has deemed final as of its date in accordance with paragraph (b)(1) of Rule 15c2-12 adopted by the Securities and Exchange Commission ("Rule 15c2-12"). SCPPA shall deliver or cause to be delivered to the Underwriters, within seven (7) business days from the date hereof and, in any event, in sufficient time to accompany any customer confirmations requesting payment, copies of an official statement relating to the Bonds, dated the date of this Purchase Contract, approved for distribution by SCPPA in the form of the Preliminary Official Statement, as amended to conform to the terms of this Purchase Contract and to reflect the reoffering terms of the Bonds and with such other changes as shall have been approved by SCPPA and agreed to by the Representative (the "Official Statement"). SCPPA shall deliver the Official Statement in such reasonable quantities as the Underwriters may request in order to comply with paragraph (b)(4) of Rule 15c2-12 and the rules of the Municipal Securities Rulemaking Board (the "MSRB"). SCPPA shall prepare the Official Statement, including any amendments thereto, in word-searchable PDF format as described in the MSRB's Rule G-32 and shall provide the electronic copy of the word-searchable PDF format of the Official Statement to the Underwriters no later than one (1) business day prior to the Closing Date (as defined in Section 7) to enable the Representative to comply with MSRB Rule G-32. The Representative agrees to deliver a copy of the Official Statement to the MSRB in accordance and to otherwise comply with all applicable MSRB rules. SCPPA hereby consents to and ratifies the use and distribution by the Underwriters of the Preliminary Official Statement in connection with the public offering of the Bonds by the Underwriters, and further confirms the authority of the Underwriters to use, and consents to the use of, the final Official Statement with respect to the Bonds in connection with the public offering and sale of the Bonds.

4. Public Offering; Determination of Issue Price.

(a) It shall be a condition to SCPPA's obligation to sell and deliver the Bonds to the Underwriters, and it shall be a condition to the Underwriters' obligation to purchase, to accept delivery of and to pay for the Bonds that the entire aggregate principal amount of the Bonds shall be issued, sold, and delivered by SCPPA and purchased, accepted, and paid for by the Underwriters on the Closing Date. The Underwriters agree to make a bona fide public offering of all of the Bonds at prices not in excess of the initial, respective public offering prices or at yields not lower than the initial, respective yields shown or derived from information shown on the inside cover of the Official Statement. Except as set forth in subsection (d) below, the Underwriters reserve the right to change such initial offering prices after such offering as they shall deem necessary in connection with the marketing of the Bonds.

(b) The Underwriters agree to assist SCPPA in establishing the issue price of the Bonds and shall execute and deliver to SCPPA at Closing an issue price certificate or similar certificate, together with the supporting pricing wires or equivalent communications, substantially in the form or forms, as applicable, attached hereto as Exhibit E, with such modifications as may be appropriate or necessary, in the reasonable judgment of the Representative, SCPPA, and Nixon Peabody LLP, Special Tax Counsel to SCPPA, to accurately reflect, as applicable, the sales price or prices or the initial offering price or prices to the [public] of the Bonds. All actions to be taken by SCPPA under this section to establish the issue price of the Bonds may be taken on behalf of SCPPA by SCPPA's municipal advisor, PFM Financial Advisors LLC (the "Municipal Advisor"), and any notice or report to be provided to SCPPA may be provided to the Municipal Advisor.

(c) Except for the Hold the Price Maturities described in subsection (d) below and Schedule I attached hereto, SCPPA will treat the first price at which 10% of each maturity of the Bonds (the "10% test") is sold to the public as the issue price of that maturity. For purposes of this Section 4, if Bonds mature on the same date but have different interest rates, each separate CUSIP number within that maturity will be treated as a separate maturity of the Bonds. Schedule I attached hereto sets forth, as of the date of this Purchase Contract, the maturities of the Bonds for which the 10% test has been satisfied (the "10% Test Maturities") and the price or prices at which the Underwriters have sold such 10% Test Maturities to the public.

(d) With respect to the maturities of the Bonds that are not 10% Test Maturities, if any, as described in Schedule I attached hereto (the "Hold the Price Maturities"), the Representative confirms that the Underwriters have offered such maturities of the Bonds to the public on or before the date of this Purchase Contract at the offering price or prices (the "initial offering price"), or at the corresponding yield or yields, set forth on Schedule I attached hereto. SCPPA and the Representative, on behalf of the Underwriters, agree that the restrictions set forth in the next sentence shall apply to the Hold the Price Maturities, which will allow SCPPA to treat the initial offering price to the public of each such maturity as of the sale date as the issue price of that maturity (the "hold the offering price rule"). So long as the hold the offering price rule remains applicable to any maturity of the Bonds, the Underwriters will neither offer nor sell any portion of such maturity of the Hold the Price Maturities to any person at a price that is higher than the initial offering price to the public during the period starting on the sale date and ending on the earlier of the following:

(1) the close of the fifth (5th) business day after the sale date; or

(2) the date on which the Underwriters have sold at least 10% of that maturity of the Hold the Price Maturities to the public at a price that is no higher than the initial offering price to the public.

The Representative will advise SCPPA promptly after the close of the 5th business day after the sale date whether the Underwriters have sold 10% of that maturity of the Hold the Price Maturities to the public at a price that is no higher than the initial offering price to the public.

(e) The Representative confirms that:

(1) any agreement among underwriters, any selling group agreement and each third party distribution agreement (to which the Representative is a party) relating to the initial sale of the Bonds to the public, together with the related pricing wires, contains or will contain language obligating each Underwriter, each dealer who is a member of the selling group, and each broker dealer that is a party to such third party distribution agreement, as applicable, to:

(A) (i) report the prices at which it sells to the public the unsold Bonds of each maturity allotted to it until it is notified by the Representative that either the 10% test has been satisfied as to the Bonds of that maturity or all Bonds of that maturity have been sold to the public, and (ii) comply with the hold the offering price rule, if applicable, in each case if and for so long as directed by the Representative and as set forth in the related pricing wires;

(B) promptly notify the Representative of any sales of Bonds that, to its knowledge, are made to a purchaser who is a related party to an underwriter participating in the initial sale of the Bonds to the public (each such term being used as defined below), and

(C) acknowledge that, unless otherwise advised by the Underwriter, dealer or broker dealer, the Representative shall assume that each order submitted by the Underwriter, dealer or broker dealer is a sale to the public; and

(2) any agreement among underwriters relating to the initial sale of the Bonds to the public, together with the related pricing wires, contains or will contain language obligating each Underwriter that is a party to a third party distribution agreement to be employed in connection with the initial sale of the Bonds to the public to require each broker dealer that is a party to such third party distribution agreement to

(A) report the prices at which it sells to the public the unsold Bonds of each maturity allotted to it until it is notified by the Representative or the Underwriter that either the 10% test has been satisfied as to the Bonds of that maturity or all Bonds of that maturity have been sold to the public; and

(B) comply with the hold the offering price rule, if applicable, in each case if and for so long as directed by the Representative or the Underwriter and as set forth in the related pricing wires

(f) SCPPA acknowledges that, in making the representations set forth in this Section 4, the Representative will rely on:

(1) the agreement of each Underwriter to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, as set forth in an agreement among underwriters and the related pricing wires,

(2) in the event a selling group has been created in connection with the initial sale of the Bonds to the public, the agreement of each dealer who is a member of the selling group to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, as set forth in a selling group agreement and the related pricing wires, and

(3) in the event that an Underwriter or a dealer who is a member of the selling group is a party to a third party distribution agreement that was employed in connection with the initial sale of the Bonds to the public, the agreement of each broker dealer that is a party to such agreement to comply with the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, as set forth in the third party distribution agreement and the related pricing wires.

(g) SCPPA further acknowledges that each Underwriter shall be solely liable for its failure to comply with its agreement regarding the requirements for establishing the issue price of the Bonds, including, but not limited to, its agreement to comply with the hold the offering price rule, if applicable to the Bonds, and that no Underwriter shall be liable for the failure of any other Underwriter, or of any dealer who is a member of a selling group, or of any broker dealer that is a party to a third party distribution agreement, to comply with its corresponding agreement.

(h) The Underwriters acknowledge that sales of any Bonds to any person that is a related party to an underwriter participating in the initial sale of the Bonds to the public (each such term as defined below) shall not constitute sales to the public for purposes of this Section 4.

(i) In lieu of making representations on behalf of other underwriters, including PNC Capital Markets LLC, as required in this Section 4 and complying with Section 4(e) and (f), the Representative may elect in the issue price certificate attached hereto as Exhibit E to hold all unsold allotments of the Hold the Price Maturities so long as the hold the offering price rule remains applicable to such Hold the Price Maturities, in which case, all representations required to be made pursuant to this Section 4 shall be made solely by, and all obligations of the Underwriters under this Section 4 with respect to the Hold the Price Maturities shall be solely the obligations of, the Representative. In the event the Representative makes an election pursuant this subsection (i), the Representative may sell some or all of the Hold the Price Maturities while the offering price rule remains applicable subject to the requirements of subsection (d) above.

(j) Further, for purposes of this Section 4:

(1) "public" means any person other than an underwriter or a related party,

(2) "underwriter" (when used with a lower case "u") means:

(i) any person that agrees pursuant to a written contract with SCPPA (or with the lead underwriter to form an underwriting syndicate) to participate in the initial sale of the Bonds to the public, and

(ii) any person that agrees pursuant to a written contract directly or indirectly with a person described in clause (i) to participate in the initial sale of the Bonds to the public (including a member of a selling group or a party to a third party distribution agreement participating in the initial sale of the Bonds to the public),

(3) a purchaser of any of the Bonds is a "related party" to an underwriter if the underwriter and the purchaser are subject, directly or indirectly, to (i) more than 50% common ownership of the voting power or the total value of their stock, if both entities are corporations (including direct ownership by one corporation of another), (ii) more than 50% common ownership of their capital interests or profits interests, if both entities are partnerships (including direct ownership by one partnership of another), or (iii) more than 50% common ownership of the value of the outstanding stock of the corporation or the capital interests or profit interests of the partnership, as applicable, if one entity is a corporation and the other entity is a partnership (including direct ownership of the applicable stock or interests by one entity of the other), and

(4) "sale date" means the date of execution of this Purchase Contract by all parties.

5. Use and Preparation of Documents. SCPPA hereby authorizes the use (including in designated electronic format as permitted by applicable MSRB rules) by the Underwriters of the Official Statement (including any supplements or amendments thereto) and, subject to any restrictions on the disclosure of their contents contained therein, the Basic Documents (as defined in Section 7(b) hereof), and the information therein contained, in connection with the public offering and sale of the Bonds. SCPPA hereby ratifies and approves the use (including electronic delivery) by the Underwriters prior to the date hereof of the Preliminary Official Statement and the Indenture in connection with the public offering of the Bonds.

6. Representations, Warranties and Agreements. SCPPA hereby represents, warrants and agrees as follows:

(a) SCPPA is an entity duly organized and validly existing pursuant to the Act and that certain Southern California Public Power Authority Joint Powers Agreement, dated as of November 1, 1980, as amended (the "SCPPA Organization Agreement"), among the parties therein named (hereinafter referred to as the "Members"), and the SCPPA Organization Agreement has been duly authorized, executed and delivered by each of the Members in accordance with the Act and other applicable provisions of the Constitution and laws of the State of California and the city charters or other applicable instruments or statutes of or pertaining to the Members;

(b) SCPPA has full legal right, power and authority (i) to enter into this Purchase Contract and to issue, sell and deliver the Bonds to the Underwriters as provided herein; (ii) to carry out and consummate the transactions contemplated by the Indenture, this Purchase Contract, the Disclosure Resolution and the Official Statement; and (iii) to carry out and consummate the transactions contemplated by the Apex Power Project Power Sales Agreement, dated as of March 1, 2013 (the "Power Sales Agreement"), by and between SCPPA and the Department of Water and Power of The City of Los Angeles as sole project participant (the "Project Participant"), Agency Agreement, dated as of March 1, 2014 (the "Agency Agreement") by and between SCPPA and the Project Participant, [O&M Agreement, LTSA, Water Agreement, Operational Balancing Authority Agreement and fuel agreements, TSAs, Interconnection Agreement, permits] and the Indenture (the Power Sales Agreement, the Agency Agreement [O&M Agreement, LTSA, Water Agreement, Operational Balancing Authority Agreement and fuel agreements, TSAs, Interconnection Agreement, permits] and the Indenture being herein collectively referred to as the "Basic Documents"); the Basic Documents have all been duly authorized by all necessary action on the part of SCPPA, and, except for those of the Basic Documents which by their terms become effective only upon the consummation of the transactions contemplated under this Purchase Contract, are in full force and effect; SCPPA has complied, or will on the Closing Date be in compliance in all material respects, with the terms of the Act, the SCPPA Organization Agreement and the Basic Documents and with the obligations in connection with the issuance of the Bonds on its part contained in the Bonds and this Purchase Contract; the Basic Documents and this Purchase Contract constitute, or upon the consummation of the transactions contemplated under this Purchase Contract will constitute, the legal, valid and binding agreements or obligations of SCPPA, and in the case of the Power Sales Agreement and the Agency Agreement constitutes the legal, valid and binding agreements of the Project Participant, enforceable in accordance with their respective terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws or equitable principles relating to or limiting creditors' rights generally and by limitations on legal remedies against public agencies in the State of California; payments by the Project Participant under the Power Sales Agreement will constitute an operating expense of the electric utility system of the Project Participant; and SCPPA is the owner of the Apex Project.

(c) By all necessary official action, SCPPA has duly adopted the Disclosure Resolution, has duly authorized the execution and delivery of the Indenture, has duly authorized and approved the preparation and use of the Preliminary Official Statement and the Official Statement to be distributed in connection with the offering, sale and distribution of the Bonds and has duly authorized and approved (i) the execution and delivery of the Bonds, this Purchase Contract and the Basic Documents, (ii) the performance by SCPPA of the obligations in connection with the issuance of the Bonds on its part contained in the Bonds, this Purchase Contract and the Basic Documents, and (iii) the consummation by it of all other transactions contemplated by this Purchase Contract and the Basic Documents in connection with the issuance of the Bonds; the Bonds, when issued and delivered to the Underwriters in accordance with the Indenture and this Purchase Contract, will constitute legal, valid and binding obligations of SCPPA, enforceable in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws or equitable principles relating to or limiting creditors' rights generally and by limitations on legal remedies against public agencies in the State of California;

(d) SCPPA is not, and will not be, in any material respect, in breach of or default under any applicable constitutional provision, law or administrative regulation of the United States or any state thereof or any agency or instrumentality of either or any applicable judgment or decree or any loan agreement, indenture, bond, note, resolution, agreement (including, without limitation, any of the Basic Documents) or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets is otherwise subject, and no event has occurred and is continuing which with the passage of time or the giving of notice, or both, would constitute such a default or event of default under any such instrument, in any case where such breach or default would materially adversely affect (i) the marketability of the Bonds or the market prices thereof, or (ii) SCPPA or its ability to perform its obligations under this Purchase Contract and the Basic Documents; the execution and delivery of the Bonds, this Purchase Contract and the Basic Documents, and compliance with the provisions on SCPPA's part contained therein, will not conflict with or constitute a breach of or default under any constitutional provision, law, administrative regulation, judgment, decree, loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets is otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, this Purchase Contract or the Basic Documents or the validity or enforceability thereof, nor will any such execution, delivery, adoption or compliance result in the creation or imposition of any lien, charge or other security interest or encumbrance of any nature whatsoever upon any of the property or assets of SCPPA or under the terms of any such law, provision, regulation or instrument, except as provided by the Bonds and the Indenture;

(e) All authorizations, approvals, licenses, permits, consents and orders of any governmental authority, legislative body, board, agency or commission having jurisdiction of the matter which are required for the due authorization by, or which would constitute a condition precedent to or the absence of which would materially adversely affect the due performance by, SCPPA of its obligations in connection with the issuance of the Bonds under this Purchase Contract or the Indenture have been duly obtained, except for such approvals, consents and orders as may be required under the Blue Sky or securities laws of any state in connection with the offering and sale of the Bonds; and, except as described in or contemplated by the Preliminary Official Statement and the Official Statement, all authorizations, approvals, licenses, permits, consents and orders of any governmental authority, board, agency or commission having jurisdiction of the matter which are required for the due authorization by, or which would constitute a condition precedent to or the absence of which would materially adversely affect the due performance by, SCPPA of its respective obligations under this Purchase Contract and the Basic Documents have been duly obtained, except those which need not be obtained until a future date;

(f) The Bonds when issued will conform to the descriptions thereof contained in the Preliminary Official Statement (except for the omission of certain information permitted to be omitted therefrom in accordance with Rule 15c2-12) and the Official Statement under the captions "INTRODUCTION," and "DESCRIPTION OF THE 2024 BONDS"; the Indenture will conform to the descriptions thereof contained in the Preliminary Official Statement and the Official Statement under the captions "INTRODUCTION," "DESCRIPTION OF THE 2024 BONDS" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 BONDS" and contained in APPENDIX [C] thereto; the Power Sales Agreement and the Agency Agreement will conform to the description thereof contained in the Preliminary Official Statement and the Official Statement under the captions "INTRODUCTION," "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 BONDS" and contained in APPENDIX [C] thereto;

(g) The Bonds, when issued, authenticated and delivered in accordance with the Indenture and sold to the Underwriters as provided herein, will be validly issued and outstanding obligations of SCPPA, entitled to the benefits of the Indenture; and upon such issuance and delivery, the Indenture will provide, for the benefit of the owners from time to time of the Bonds, the legally valid and binding pledge and lien and security interest it purports to create;

(h) Between the date of this Purchase Contract and the Closing Date, SCPPA will not, without the prior written consent of the Representative, offer or issue any notes, bonds or other obligations for borrowed money, or incur any material liabilities, direct or contingent, with respect to the Apex Power Project, except in the course of normal business operations of SCPPA or except for refinancings for savings on outstanding bonds or except for such borrowings as may be described in or contemplated by the Official Statement or otherwise disclosed in writing to the Representative, nor will there be any adverse change of a material nature in the financial position, results of operations or condition, financial or otherwise, of SCPPA;

(i) As of the date hereof, except for the litigation (A) described or referred to in the Preliminary Official Statement and the Official Statement under the caption "LITIGATION," and the subcaption "LITIGATION" under the caption "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES" contained in APPENDIX A thereto, or (B) otherwise disclosed in writing to the Representative on or before the date of this Purchase Contract, there is no action, suit, proceeding, inquiry or investigation, at law or in equity before or by any court, government agency, public board or body, pending or, to the best knowledge of the officer of SCPPA executing this Purchase Contract, threatened against SCPPA (nor to the best knowledge of such officer is there any such action, suit, proceeding, inquiry or investigation pending or threatened against the Project Participant), affecting the existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain or enjoin the sale, issuance or delivery of the Bonds or the collection of the revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the Revenues or other funds and accounts to be established pursuant to the Indenture, or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, this Purchase Contract or any Basic Document, or contesting the federal tax-exempt status of interest on the Bonds or the tax-exempt status of interest on the Bonds for State of California income tax purposes, or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement, or contesting the powers of SCPPA or any authority for the issuance of the Bonds or the execution and delivery or adoption, as applicable, by SCPPA of this Purchase Contract or any Basic Document, or in any way contesting or challenging the consummation of the transactions contemplated hereby or thereby, or which would result in a material adverse change in the financial condition of SCPPA or which would materially adversely affect the generating capacity or output of the Apex Power Project; nor, to the best knowledge of SCPPA, is there any basis for any such action, suit, proceeding, inquiry or investigation, wherein an unfavorable decision, ruling or finding would materially adversely affect the validity of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or this Purchase Contract;

(j) SCPPA will furnish such information, execute such instruments and take such other action in cooperation with the Underwriters as the Representative may reasonably request in order

(i) to qualify the Bonds for offer and sale under the Blue Sky or other securities laws and regulations of such states and other jurisdictions of the United States as the Representative may designate, and (ii) to determine the eligibility of the Bonds for investment under the laws of such states and other jurisdictions, and will use its best efforts to continue such qualifications in effect so long as required for the distribution of the Bonds; provided, however, that SCPPA shall not be required to execute a general or special consent to service of process or qualify to do business in connection with any such qualification or determination in any jurisdiction;

(k) As of its date and at the time of SCPPA's acceptance hereof, the Preliminary Official Statement (as supplemented and amended, if applicable), except for the omission of certain information permitted to be omitted therefrom in accordance with Rule 15c2-12, did not and does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(l) At the time of delivery thereof to the Underwriters and (unless an event occurs of the nature described in paragraph (n) of this Section 6) at all times subsequent thereto to and including the Closing Date, the Official Statement will not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(m) If the Official Statement is supplemented or amended pursuant to paragraph (n) of this Section 6, at the time of each supplement or amendment thereto and (unless subsequently again supplemented or amended pursuant to such paragraph) at all times subsequent thereto, to and including the Closing Date, the Official Statement as so supplemented or amended will not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(n) If between the date of this Purchase Contract and that date which is 25 days after the end of the underwriting period (as determined in accordance with Section 15 hereof) any event shall occur or be discovered by SCPPA affecting SCPPA, the Revenues pledged or to be pledged to pay the principal of and interest on the Bonds or the or the Project Participant which might adversely affect the marketability of the Bonds or the market prices thereof, or which might cause the Official Statement, as then supplemented or amended, to contain any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading, SCPPA shall notify the Representative thereof (and shall provide to the Representative such information concerning such event as the Representative may reasonably request) and, if in the opinion of the Representative such event requires the preparation and publication of a supplement or amendment to the Official Statement, SCPPA will at its expense prepare and furnish to the Underwriters a reasonable number of copies of such supplement to, or amendment of, the Official Statement, in a form and in a manner approved by the Representative;

(o) SCPPA will apply the proceeds from the sale of the Bonds for the purposes specified in the Official Statement;

(p) SCPPA has not failed during the previous five years to comply in any material respect with any previous undertakings in any written continuing disclosure contract or agreement under Rule 15c2-12; and

(q) Any certificate signed by an official of SCPPA authorized to do so in connection with the transactions described in this Purchase Contract and delivered pursuant to Section 9(e) shall be deemed to be a representation by SCPPA to the Underwriters as to the statements made therein.

7. Closing. At 8:00 a.m., Los Angeles time, on ______, 2024 or at such earlier or later time or date as shall be mutually agreed upon by SCPPA and the Representative (such time and date being herein referred to as the "Closing Date"), SCPPA will, subject to the terms and conditions hereof, sell and deliver the Bonds to or for the account of the Underwriters in definitive form, duly executed and authenticated, together with the other documents hereinafter mentioned, and, subject to the terms and conditions hereof, the Underwriters will accept such delivery and pay the purchase price of the Bonds as set forth in Section 1 hereof by federal funds wire or certified or official bank check or checks in federal funds immediately available in Los Angeles, California to the order of SCPPA. Sale, delivery and payment as aforesaid shall be made at the offices of Norton Rose Fulbright US LLP, 555 South Flower Street, 41st Floor, Los Angeles, California, or such other place as shall have been mutually agreed upon by SCPPA and the Representative, except that the Bonds shall be delivered through the facilities of The Depository Trust Company ("DTC") in New York, New York, or at such other place as shall have been mutually agreed upon by SCPPA and the Representative, in fully registered, book-entry eligible form (which may be typewritten) and registered in the name of Cede & Co., as nominee of DTC.

8. Closing Conditions. The Underwriters have entered into this Purchase Contract in reliance upon the representations and warranties of SCPPA contained herein, and in reliance upon the representations and warranties to be contained in the documents and instruments to be delivered pursuant hereto on or prior to the Closing Date and upon the performance by SCPPA of its obligations hereunder, both as of the date hereof and as of the Closing Date. Accordingly, the Underwriters' obligations under this Purchase Contract to purchase, to accept delivery of and to pay for the Bonds shall be conditioned upon the performance by SCPPA of its obligations to be performed hereunder and under such documents and instruments on or prior to the Closing Date, and shall also be subject to the following additional conditions:

(a) The representations and warranties of SCPPA contained herein shall be true, complete and correct on the date hereof and on and as of the Closing Date, as if made on the Closing Date;

(b) As of the Closing Date, the SCPPA Organization Agreement and each of the Basic Documents shall be in full force and effect in accordance with their respective terms and, shall not have been amended, modified or supplemented, and the Official Statement shall not have been supplemented or amended, except in any such case as may have been agreed to by the Representative;

(c) As of the Closing Date, all necessary official action of SCPPA and of the other parties thereto relating to this Purchase Contract, the SCPPA Organization Agreement and the

Basic Documents shall have been taken and shall be in full force and effect and shall not have been amended, modified or supplemented in any material respect, except in any such case as may have been agreed to by the Representative;

(d) As of the Closing Date, there shall not have occurred any change in or affecting particularly SCPPA or the Project Participant, the Bonds, the Revenues, the status of operation or required permits, licenses or approvals relating to the Apex Power Project, as the foregoing matters are described in the Official Statement, which in the opinion of the Representative materially impairs the investment quality or marketability of the Bonds;

(e) On or prior to the Closing Date, the Representative, on behalf of the Underwriters, shall have received a copy of each of the following documents:

(1) The Official Statement and each supplement or amendment, if any, thereto, executed on behalf of SCPPA by its President, Vice President or Executive Director;

(2) A copy of each of the Basic Documents as executed by the parties thereto;

(3) The approving legal opinion, dated the Closing Date and addressed to SCPPA, of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel to SCPPA, substantially in the form included in the Official Statement as Appendix __ thereto;

(4) The opinion, dated the Closing Date and addressed to SCPPA, of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel to SCPPA, substantially in the form included in the Official Statement as Appendix __ thereto;

(5) An opinion, dated the Closing Date and addressed to the Underwriters, of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel and Disclosure Counsel to SCPPA, substantially in the form attached hereto as Exhibit A;

(6) An opinion, dated the Closing Date and addressed to the Underwriters, of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel to SCPPA, substantially in the form attached hereto as Exhibit F.

(7) An opinion, dated the Closing Date and addressed to the Underwriters, of General Counsel to SCPPA, substantially in the form attached hereto as Exhibit B;

(8) A certificate, dated the Closing Date, signed by the President, Vice President or Executive Director of SCPPA, substantially in the form attached hereto as Exhibit C (but in lieu of or in conjunction with paragraph 2 of such certificate the Representative may, in its sole discretion, accept certificates or opinions of Norton Rose Fulbright US LLP, Los Angeles, California, or of other counsel acceptable to the Representative, that in the opinion of such counsel the issues raised in any pending or threatened litigation referred to in such certificate are without substance or that the contentions of all plaintiffs therein are without merit);

(9) Certificates, dated the Closing Date, signed in each case by an authorized representative of the Project Participant, substantially in the form attached hereto as Exhibit D;

(10) An opinion, dated the Closing Date and addressed to the Underwriters, of Hawkins Delafield & Wood LLP, counsel to the Underwriters, to the effect that (i) the Bonds are not subject to the registration requirements of the Securities Act of 1933, as amended, and the Indenture is exempt from qualification pursuant to the Trust Indenture Act of 1939, as amended, (ii) based upon the participation of such firm in the preparation of the Preliminary Official Statement and the Official Statement, as the case may be, and without having undertaken to determine independently the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement, nothing has come to the attention of the attorneys in such firm rendering legal services in connection with such representation that caused them to believe that the Preliminary Official Statement, as of its date and as of _________, 2024, or the Official Statement, as of its date and as of the Closing Date (excluding therefrom the financial statements or other financial or statistical data or forecasts and the information concerning DTC and the book-entry only system, the discussions contained therein of permits, licenses and approvals required for the continued operation of the Apex Power Project, or the other activities or projects of SCPPA or other projects of the Project Participant, and the status of each, the description of any litigation, the financial and statistical information with respect to the Project Participant contained in the Preliminary Official Statement and the Official Statement, and Appendices B, C, D, E and F thereto, as to all of which no opinion is expressed), contained or contains an untrue statement of material fact or omitted or omits to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading; and (iii) assuming the due authorization and adoption of the Disclosure Resolution by SCPPA and the enforceability thereof, the Disclosure Resolution satisfies clause (b)(5)(i) of Rule 15c2-12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), which requires an undertaking for the benefit of the holders, including beneficial owners, of the Bonds to provide annual updates of certain Official Statement information and certain event notices to the MSRB at the times and in the manner required by such Rule;

(11) A transcript of all proceedings relating to the authorization and issuance of the Bonds certified by the Secretary or an Assistant Secretary of SCPPA, including the Disclosure Resolution;

(12) A bring-down opinion of counsel to the Project Participant, dated the Closing Date and addressed to SCPPA and the Underwriters, in the form acceptable to the Representative;

(13) An opinion, dated the Closing Date and addressed to SCPPA and the Underwriters, of counsel to the Trustee, in form and substance acceptable to SCPPA and the Representative, to the effect that the Trustee is duly authorized to execute, deliver and perform its obligations under the Indenture, and the Indenture is valid, binding and enforceable against the Trustee in accordance with its terms; and

(14) Such additional legal opinions, certificates, instruments and other documents as the Representative may reasonably request to evidence the truth and accuracy, as of the date hereof and as of the Closing Date, of SCPPA's representations and warranties contained herein and of the statements and information contained in the Official Statement and the due performance or satisfaction by SCPPA on or prior to the Closing Date of all the agreements then to be performed and conditions then to be satisfied by it; and

(f) The Bonds shall have been rated at least "___" and "___" by Fitch Ratings, Inc. and Moody's Investors Service, respectively; and such ratings shall not have been suspended, revoked or downgraded.

All the opinions, letters, certificates, instruments and other documents mentioned above or elsewhere in this Purchase Contract shall be deemed to be in compliance with the provisions hereof if, but only if, they are in form and substance satisfactory to the Representative; provided, however, the opinions and certificates referred to in clauses (3), (4), (5), (6), (7), (8) and (9) of paragraph (e) of this Section, inclusive, shall be deemed satisfactory provided they are substantially in the respective forms attached as an appendix to the Official Statement or as exhibits to this Purchase Contract.

If SCPPA shall be unable to satisfy the conditions to the obligations of the Underwriters to purchase, to accept delivery of and to pay for the Bonds contained in this Purchase Contract, or if the obligations of the Underwriters to purchase, to accept delivery of and to pay for the Bonds shall be terminated for any reason permitted by this Purchase Contract, this Purchase Contract shall terminate and neither the Underwriters nor SCPPA shall be under any further obligation hereunder, except that the respective obligations of SCPPA and the Underwriters set forth in Sections 10 and 12 hereof shall continue in full force and effect.

9. Termination. The Underwriters shall have the right to terminate their obligations under this Purchase Contract to purchase, to accept delivery of and to pay for the Bonds by the Representative notifying SCPPA of their election to do so if, after the execution hereof and prior to the Closing Date:

(i) an event or circumstance shall exist which makes untrue or incorrect in any material respect any statement or information contained in the Official Statement or which is not reflected in the Preliminary Official Statement or the Official Statement but should be reflected therein in order to make the statements made therein in the light of the circumstances under which they were made not misleading in any material respect, and, in either such event, (a) SCPPA refuses to permit the Official Statement to be supplemented to supply such statement or information in a manner satisfactory to the Representative or (b) the effect of the Official Statement as so supplemented is, in the reasonable judgment of the Representative, to materially adversely affect the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale of the Bonds; or

(ii) legislation shall be enacted by the State of California or by the United States, recommended to the legislature of the State of California by the Governor or to the Congress for passage by the President of the United States, or favorably reported for passage to either house of the legislature of the State of California or either house of the Congress by any committee of any such house to which such legislation has been referred for consideration, or a decision shall be rendered by any court of the State of California or the United States of competent jurisdiction, or a ruling or regulation (final, temporary or proposed) shall be issued on behalf of the Treasury Department of the United States, the Internal Revenue Service or any other authority of the United States, affecting the tax-exempt status of SCPPA or the interest on its bonds or its notes (including the Bonds) for federal or State of California income tax purposes which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(iii) any action shall have been taken by (a) the Securities and Exchange Commission or by a court of competent jurisdiction which would require registration of the Bonds under the Securities Act of 1933, as amended, or qualification of any indenture under the Trust Indenture Act of 1939, as amended, in connection with the public offering of the Bonds or the effect of which is that the issuance, offering or sale of the Bonds as contemplated would be in violation of the federal securities laws as amended and in effect; or (b) any court or by any governmental authority suspending the offering or sale of the Bonds or the use of the Official Statement or any amendment or supplement thereto; or

(iv) there shall have been (1) a declaration of war or engagement in or escalation of military hostilities by the United States or any act of terrorism or (2) any other calamity or crisis (or material escalation in any calamity or crisis), which in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(v) there shall have occurred the declaration of a general banking moratorium by any authority of the United States or the States of New York or California or a material disruption in commercial banking or securities settlement or clearance services shall have occurred which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(vi) there shall have occurred a general suspension of trading, minimum or maximum prices for trading shall have been fixed and be in force or maximum ranges or prices for securities shall have been required on the New York Stock Exchange or other national stock exchange whether by virtue of a determination by that Exchange or by order of the Securities and Exchange Commission or any other governmental agency having jurisdiction or any national securities exchange shall have (a) imposed additional material restrictions not in force as of the date hereof with respect to trading in securities generally, or to the Bonds or similar obligations; or (b) materially increased restrictions now in force with respect to the charge to the net capital requirements of Underwriters or broker dealers which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(vii) there shall have occurred any materially adverse change in the affairs or financial condition of SCPPA, which, in the reasonable judgment of the Representative, materially adversely affects the market prices or marketability of the Bonds or the ability of the Underwriters to enforce contracts for the sale, at the contemplated offering prices (or yields), of the Bonds; or

(viii) there shall have been a downgrading, suspension or withdrawal of the rating on the Bonds, or the rating on the Bonds shall have been placed on "credit watch" or "negative outlook" or similar qualification.

10. Expenses.

(a) The Underwriters shall be under no obligation to pay, and SCPPA shall pay, any expenses incident to the performance of SCPPA's obligations hereunder including, but not limited to: (i) the cost of preparation and printing of the Indenture, the Preliminary Official Statement and the Official Statement and any supplements or amendments thereto; (ii) the cost of preparation and printing of the Bonds; (iii) the fees and disbursements of Norton Rose Fulbright US LLP, Bond Counsel to SCPPA and the fees and expenses of counsel to SCPPA; (iv) the fees and disbursements, if any, of the Trustee; (v) the fees and disbursements of PFM Financial Advisors LLC for its services as municipal advisor to SCPPA with regards to the Apex Power Project; (vi) the fees and disbursements of any engineers, accountants and other experts, consultants or advisers retained by SCPPA or providing letters, opinions or reports to SCPPA or the Underwriters pursuant to this Purchase Contract; (vii) fees for bond ratings; (viii) the cost of preparation of this Purchase Contract and the Blue Sky Memorandum; (ix) all advertising expenses and Blue Sky filing fees in connection with the public offering of the Bonds; (x) any expenses for air travel, hotel costs, meals and transportation for SCPPA employees in connection with the pricing of the Bonds, any investor meetings, any rating agency trips and the Closing; and (xi) any other miscellaneous Closing costs. SCPPA acknowledges that it has had an opportunity, in consultation with such advisors as it may deem appropriate, if any, to evaluate and consider the fees and expenses being incurred as part of the issuance of the Bonds.

(b) SCPPA has agreed to pay the Underwriters' discount set forth in Section 1 of this Purchase Contract, and inclusive in the expense component of the Underwriters' discount are expenses incurred or paid for by the Underwriters on behalf of SCPPA in connection with the marketing, issuance, and delivery of the Bonds, including, but not limited to, advertising expenses, fees and expenses of Underwriters' Counsel, the costs of any Preliminary and Final Blue Sky Memoranda, CUSIP Global Services and DTC in connection with the issuance of the Bonds, and transportation, lodging, and meals for SCPPA's employees and representatives in connection with the sale and issuance of the Bonds. The Underwriters are required to pay fees to the California Debt and Investment Advisory Commission in connection with the offering of the Bonds. Notwithstanding that such fees are solely the legal obligation of the Underwriters, SCPPA agrees to reimburse the Underwriters for such fees.

(c) Notwithstanding the foregoing, if the Underwriters or SCPPA shall bring an action to enforce any part of this Purchase Contract against the other, each party shall bear its attorneys' fees and costs incurred in connection with such action.

11. Notices. Any notice or other communication to be given to SCPPA under this Purchase Contract may be given by delivering the same in writing at SCPPA's address set forth above, and any notice or other communication to be given to the Representative or to the Underwriters under this Purchase Contract may be given by delivering the same in writing to J. P. Morgan Securities LLC, 560 Mission Street, 3rd Floor San Francisco, CA 94105 Attention: Will Frymann.

12. Parties in Interest. This Purchase Contract is made solely for the benefit of SCPPA and the Underwriters (including the successors or assigns of the Underwriters) and no other person shall acquire or have any right hereunder or by virtue hereof. All of SCPPA's representations, warranties and agreements contained in this Purchase Contract shall remain operative and in full force and effect, regardless of: (i) any investigations made by or on behalf of the Underwriters; (ii) delivery of and payment for the Bonds pursuant to this Purchase Contract; and (iii) any termination of this Purchase Contract.

13. Effectiveness. This Purchase Contract shall become effective upon the execution of the acceptance by the President, any Vice President, the Executive Director or the Chief Financial and Administrative Officer of SCPPA and shall be valid and enforceable at the time of such acceptance.

14. Headings. The headings of the sections of this Purchase Contract are inserted for convenience only and shall not be deemed to be a part hereof.

15. End of Underwriting Period. The term "end of the underwriting period" referred to in Section 6(n) of this Purchase Contract shall mean the later of such time as (i) SCPPA delivers the Bonds to the Underwriters, or (ii) the Underwriters do not retain an unsold balance of the Bonds for sale to the public. Unless the Representative gives notice to the contrary, the end of the underwriting period shall be deemed to be the Closing Date. Any notice delivered pursuant to this

Section 15 shall be delivered in writing to SCPPA at or prior to the Closing Date, and shall specify a date, other than the Closing Date (or such other date previously specified by notice delivered pursuant to this Section 15), to be deemed the end of the underwriting period. In no event, without the prior agreement of SCPPA, shall the end of the underwriting period be a date more than 90 days after the Closing Date.

16. **Counterparts**. This Purchase Contract may be executed in several counterparts, each of which shall be regarded as an original and all of which shall constitute one and the same document.

17. **Representation By Counsel; Drafting**. The Underwriters and SCPPA each acknowledge that it has been represented by counsel in negotiating and drafting this Purchase Contract. Each provision of this Purchase Contract shall be construed with the recognition that both parties participated in the drafting of the same. Thus, any rule of construction that requires this Purchase Contract to be construed against the drafting party shall not be applicable.

18. **Arm's Length Commercial Transaction**. SCPPA acknowledges and agrees that (i) the purchase and sale of the Bonds pursuant to this this Purchase Contract is an arm's-length commercial transaction between SCPPA and the Underwriters, (ii) in connection with such transaction, each Underwriter is acting solely as a principal and not as an agent, a Municipal Advisor (within the meaning of Section 15B of the Exchange Act, financial advisor or a fiduciary of SCPPA, (iii) the Underwriters have not assumed (individually or collectively) a fiduciary responsibility in favor of SCPPA with respect to the offering of the Bonds or the process leading thereto (whether or not any Underwriter, or any affiliate of an Underwriter, has advised or is currently advising SCPPA on other matters) or any other obligation to SCPPA except the obligations expressly set forth in this Purchase Contract, and (iv) SCPPA has consulted with its own legal and financial advisors to the extent it deemed appropriate in connection with the offering of the Bonds.

19. **Compensation**. The Underwriters acknowledge and agree that (1) the compensation received by the Underwriters in connection with this Purchase Contract was determined pursuant to an arm's length transaction as specified in Section 18 above; (2) no other compensation received for such services was received from sources other than proceeds of the Bonds; and (3) such compensation only covers services in connection with the issuance of the Bonds and this Purchase Contract.

20. **Governing Law**. This Purchase Contract shall be construed in accordance with the laws of the State of California. Any action arising hereunder shall be filed and maintained in Los Angeles County, California.

21. **Severability**. If any provision of this Purchase Contract shall be held to be invalid, illegal or unenforceable in any respect, then such provision shall be deemed severable from the remaining provisions contained in this Purchase Contract and such invalidity, illegality or unenforceability shall not affect any other provision of this Purchase Contract.

22. **Entire Agreement; Amendments**. This Purchase Contract constitutes the entire agreement between the parties hereto with respect to the matters covered hereby, and supersedes all prior agreements and understandings between the parties. This Purchase Contract shall only be amended, supplemented or modified in a writing signed by both of the parties hereto.

[REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK]

Very truly yours,

J. P. MORGAN SECURITIES LLC
PNC CAPITAL MARKETS LLC

By J. P. Morgan Securities LLC, representative of the Underwriters

By:______________________________________
Executive Director

Accepted on this ___ day of _____, 2024:

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By: __________________________________
Chief Financial and
Administrative Officer

SCHEDULE I

$______________
Apex Power Project,
Refunding Revenue Bonds, 2024 Series A

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	Price

* 10% Test has been satisfied on all maturities.

EXHIBIT A

Opinion to the Underwriters of
Norton Rose Fulbright US LLP

[Letterhead of Norton Rose Fulbright US LLP]

__________, 2024

J. P. Morgan Securities LLC
PNC Capital Markets LLC
c/o J. P. Morgan Securities LLC
San Francisco, California

Re: Southern California Public Power Authority
Apex Power Project, Refunding Revenue Bonds, 2024 Series A

Ladies and Gentlemen:

This letter is delivered to you, as underwriters, pursuant to Section 8(e)(5) of the Purchase Contract, dated _________, 2024 (the "Purchase Contract"), between J. P. Morgan Securities LLC, as your representative, and Southern California Public Power Authority (the "Authority").

As used herein, the terms "Indenture," "Preliminary Official Statement," "Official Statement," "Basic Documents," "Power Sales Agreement," "Agency Agreement" and "Participant" shall have the respective meanings ascribed thereto in the Purchase Contract.

We deliver herewith a copy of our opinion, dated the date hereof and addressed to the Authority, as to the validity of the Authority's Apex Power Project, Refunding Revenue Bonds, 2024 Series A, issued in the aggregate principal amount of $______________ (the "Bonds"). This will confirm that you may rely upon such opinion as if the same were addressed to you. We express no view or opinion as to the validity or binding or enforceable nature of any of the Basic Documents, except as set forth in such opinion.

We are of the opinion that:

1. The Bonds are not subject to the registration requirements of the Securities Act of 1933, as amended, and the Indenture is exempt from qualification pursuant to the Trust Indenture Act of 1939, as amended;

2. The statements contained in the Preliminary Official Statement and the Official Statement under the captions "INTRODUCTION," "DESCRIPTION OF THE 2024 BONDS" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 BONDS" and contained in Appendix __ thereto (excluding the statements under each such caption relating to The Depository Trust Company ("DTC"), Cede & Co. or the book-entry only system, as to all of which we express no view), insofar as the statements contained under such captions purport to summarize certain provisions of the Bonds and the Basic Documents, present an accurate summary of such provisions and opinion for the purpose of use in the Preliminary Official Statement and the Official Statement;

3. No order, filing, consent, approval, exemption of or registration with any governmental authority (other than such filings or registration as have been completed or orders, consents, or approvals as have been obtained) is required in connection with the execution and delivery by the Authority of the Bonds or the Indenture;

4. Under the Constitution and laws of the State of California, the Power Sales Agreement and the Agency Agreement constitutes a valid and binding agreement of the Project Participant enforceable in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid, binding and enforceable nature of the Power Sales Agreement or the Agency Agreement: (i) the legal existence or formation of the Project Participant or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of the Project Participant, including, without limitation, any proceedings relating to the negotiation or authorization of any Power Sales Agreement or the Agency Agreement or the execution, delivery or performance thereof (except that we have examined the respective ordinances and resolutions pursuant to which the Power Sales Agreement or the Agency Agreement was authorized by the Project Participant), (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than the Power Sales Agreement and the Agency Agreement) or any governmental order, regulation or rule of or applicable to the Project Participant, (iv) any judicial order, judgment or decree in a proceeding to which the Project Participant is a party, or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by the Project Participant of its Power Sales Agreement or the Agency Agreement. The Authority has heretofore received, independent from this opinion, opinions with respect to, among other things, the validity and enforceability of the Power Sales Agreement and the Agency Agreement rendered by legal counsel to the Project Participant; and

5. The Purchase Contract has been duly authorized, executed and delivered by the Authority, and assuming due authorization, execution and delivery by the other party thereto, constitutes a legal, valid and binding agreement of the Authority.

The opinions expressed in paragraphs 4 and 5 hereof are qualified to the extent that the enforceability of the Power Sales Agreement, the Agency Agreement and the Purchase Contract may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights generally, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases or as to the availability of any particular remedy. In addition, the enforceability of the Power Sales Agreement, the Agency Agreement and the Purchase Contract is subject to the effect of general principles of equity, including, without limitation, concepts of materiality, reasonableness, good faith and fair dealing, to the possible unavailability of specific performance or injunctive relief, regardless of whether considered in a proceeding in equity or at law, and to the limitations on legal remedies against public agencies in the State of California. We express no opinion as to any indemnification, contribution, penalty, choice of law, choice of forum or waiver provisions contained in the foregoing documents.

Based upon our participation in the preparation of the Preliminary Official Statement and the Official Statement as Bond Counsel and Disclosure Counsel to the Authority and upon the information made available to us in the course of the foregoing, but without having undertaken to determine or verify independently or assuming any responsibility for the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement (except to the extent expressly set forth in paragraph 2 above), as of the date hereof nothing has come to the attention of the personnel directly involved in rendering legal advice and assistance in connection with the preparation of the Preliminary Official Statement and the Official Statement that causes us to believe that (a) the Preliminary Official Statement, as of its date or as of __________, 2024, contained any untrue statement of a material fact or omitted to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom the discussions contained in the Preliminary Official Statement of permits, licenses and approvals required for the operation of the Apex Power Project (as defined in the Preliminary Official Statement) or other activities of the Authority or other projects of the Authority or the Project Participant, and the status thereof, the description of any litigation, any information relating to DTC, Cede & Co. and the book-entry system, forecasts, projections, estimates, assumptions and expressions of opinions, the financial, statistical and other information with respect to the Project Participant, and the other financial and statistical data included therein, as to all of which we express no view, and except for such information as is permitted to be excluded from the Preliminary Official Statement pursuant to Rule 15c2-12 of the Securities Exchange Act of 1934, as amended, including, but not limited to information as to pricing, yields, interest rates, maturities, amortization, redemption provisions, debt service requirements, underwriters' discount and CUSIP numbers), or (b) the Official Statement, as of its date or as of the date hereof, contained or contains any untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom the discussions contained in the Official Statement of permits, licenses and approvals required for the operation of the Apex Power Project (as defined in the Official Statement) or other activities of the Authority or other projects of the Authority or the Project Participant, and the status thereof, the description of any litigation, any information relating to DTC, Cede & Co. and the book-entry system, forecasts, projections, estimates, assumptions and the financial, statistical and other information with respect to the Project Participant, and the other financial and statistical data included therein, as to all of which we express no view).

During the period from the date of the Preliminary Official Statement to the date of this opinion, except for our review of the certificates and opinions regarding the Preliminary Official Statement and the Official Statement delivered on the date hereof, we have not undertaken any procedures or taken any actions which were intended or likely to elicit information concerning the accuracy, completeness or fairness of any of the statements contained in the Preliminary Official Statement or the Official Statement.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions. Such opinions may be adversely affected by actions taken or events occurring, including a change in law, regulation or ruling (or in the application or official interpretation of any law, regulation or ruling) after the date hereof. We have not undertaken to determine, or to inform any person, whether such actions are taken or such events occur, and we have no obligation to update this opinion in light of any such actions or events.

We are furnishing you this letter at the request of the Authority and solely for the information of, and assistance to, you in conducting and documenting your investigation of the affairs of the Authority in connection with the offering of the Bonds, and it is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of the Bonds, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that it may be included in, and reference may be made to it in any list of, the closing documents pertaining to the delivery of the Bonds. The provision of this opinion letter to you shall not create any attorney-client relationship between our firm and you. This opinion letter may not be relied upon by any other person, firm, corporation or other entity without our prior written consent, and we have no obligation to update this opinion.

Very truly yours,

EXHIBIT B

[Opinion to the Underwriters of General Counsel to SCPPA]

[Letterhead of General Counsel to SCPPA]

__________, 2024

J. P. Morgan Securities LLC
PNC Capital Markets LLC
c/o J. P. Morgan Securities LLC
San Francisco, California

Re: Southern California Public Power Authority
Apex Power Project, Refunding Revenue Bonds, 2024 Series A

Ladies and Gentlemen:

I am General Counsel to Southern California Public Power Authority ("SCPPA"), a joint exercise of powers agency organized and existing pursuant to Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the "Act"). This opinion is rendered pursuant to Section 8(e)(7) of the Purchase Contract, dated _____, 2024 (the "Purchase Contract"), by and between SCPPA and J. P. Morgan Securities LLC, as representative (the "Representative") of the underwriters named therein (the "Underwriters") relating to the sale of SCPPA's Apex Power Project, Refunding Revenue Bonds, 2024 Series A, issued in the aggregate principal amount of $______________ (the "Bonds").

As used herein, the terms "SCPPA Organization Agreement," "Basic Documents," "Preliminary Official Statement," "Official Statement," "Indenture," "Participant," "Power Sales Agreement," "Agency Agreement" and "DTC" shall have the respective meanings ascribed thereto in the Purchase Contract.

I am of the opinion that:

1. SCPPA is a joint powers authority duly organized and validly existing under the Act and the SCPPA Organization Agreement, and has full legal right, power and authority to execute and deliver, and to perform its obligations under, the Basic Documents and the Purchase Contract.

2. SCAPP is the owner of the Apex Power Project and such Apex Power Project is not subject to any material encumbrances that could adversely affect SCPPA's performance under the Basic Documents.

3. Assuming the due authorization, execution and delivery of the SCPPA Organization Agreement by the parties thereto (the "Members"), the SCPPA Organization Agreement constitutes the legal, valid and binding obligation of the Members, enforceable against the Members in accordance with its terms.

4. The Purchase Contract and the Basic Documents have been duly authorized, executed and delivered by SCPPA, and, assuming due authorization, execution and delivery by each of the other respective parties thereto, the Purchase Contract and the Basic Documents constitute the legal, valid and binding obligations of SCPPA, enforceable against SCPPA in accordance with their respective terms.

5. Except as disclosed in the Preliminary Official Statement and the Official Statement, no order, filing, consent, approval, exemption of or registration with any governmental authority (other than such filings or registrations as have been completed or orders, consents or approvals as have been obtained) is required in connection with the execution and delivery by SCPPA of the Bonds, the Basic Documents or the Purchase Contract; provided, however, that no opinion is expressed with respect to qualification of the Bonds for sale under blue sky or other state securities laws.

6. The statements contained in the Preliminary Official Statement and the Official Statement under the caption "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY" present a fair and accurate description of SCPPA for the purpose of use in the Preliminary Official Statement and the Official Statement, respectively.

7. SCPPA is not in material breach of or default under any applicable constitutional provision, law or administrative regulation of the State of California or the United States or any applicable judgment or decree or any loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets are otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof, and no event has occurred and is continuing which with the passage of time or the giving of notice, or both, would constitute a material default or event of default under any such instrument, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof.

8. The execution and delivery of the Bonds, the Purchase Contract and the Basic Documents and compliance with the provisions on SCPPA's part contained therein, will not conflict with or constitute a material breach of or default under any constitutional provision, law, administrative regulation, judgment, decree, loan agreement, indenture, bond, note, resolution, agreement or other instrument to which SCPPA is a party or to which SCPPA or any of its property or assets are otherwise subject, the result of which would materially adversely affect SCPPA's ability to meet its obligations under the Bonds, the Purchase Contract or the Basic Documents or the validity or enforceability thereof, nor will any such execution, delivery, adoption or compliance result in the creation or imposition of any lien, charge or other security interest or encumbrance of any nature whatsoever upon any of the property or assets of SCPPA or under the terms of any such provision, law, regulation, resolution or instrument, except as provided by the Bonds, the Indenture and the other Basic Documents.

9. The charges to be made by SCPPA for power and energy sold to the Project Participant under the Power Sales Agreement are not subject to regulation by any authority of the State of California or the United States.

10. As of the date hereof, except as described in the Preliminary Official Statement and the Official Statement under the caption "LITIGATION" or otherwise disclosed in writing to the Representative, to the best of my knowledge, there is no action, suit, proceeding, inquiry or investigation, at law or in equity, before or by any court, government agency, public board or body, pending or threatened against SCPPA affecting the corporate existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain, or enjoin the issuance, sale or delivery of the Bonds or the collection of the Revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the revenues, funds and accounts established pursuant to the Indenture, or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, the Purchase Contract or any Basic Document, or SCPPA's ability to perform its obligations and transactions under the Basic Documents, or contesting the federal tax-exempt status of interest on the Bonds or the tax-exempt status of interest on the Bonds for State of California income tax purposes or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement or any supplement or amendment thereto, or contesting the powers of SCPPA or any authority for the issuance of the Bonds, or the execution and delivery by SCPPA of the Purchase Contract or any Basic Document, nor, to the best of my knowledge, is there any basis for any such action, suit, proceeding, inquiry or investigation wherein any unfavorable decision, ruling or finding would materially adversely affect the validity or enforceability of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or the Purchase Contract.

Based upon my participation in the preparation of the Preliminary Official Statement and the Official Statement as counsel for SCPPA and without having undertaken to determine independently the accuracy, completeness or fairness of the statements contained in the Preliminary Official Statement or the Official Statement (except to the extent expressly set forth in paragraph 5 above), as of the date hereof, nothing has come to my attention which would cause me to believe that: (A) the Preliminary Official Statement, as of its date and as of __________, 2024 (as supplemented or amended pursuant to paragraph (n) of Section 6 of the Purchase Contract, if applicable), contained any untrue statement of a material fact or omitted to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom discussions contained in the Preliminary Official Statement of permits, licenses and approvals required for the operation of the Apex Power Project (as defined in the Preliminary Official Statement), or other activities of SCPPA or other projects of the Project Participant, and the status of each, any information relating to DTC, Cede & Co. or the book-entry only system, the financial, statistical and other information with respect to the Project Participant, and the other financial and statistical data included therein, as to all of which I express no view; or (B) the Official Statement, as of its date and as of the date hereof (as supplemented or amended pursuant to paragraph (n) of Section 6 of the Purchase Contract, if applicable), contained or contains any untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading (excluding therefrom discussions contained in the Official Statement of permits, licenses and approvals required for the operation of the Apex Power Project (as defined in the Official Statement), or other activities of SCPPA or other projects of the Project Participant, and the status of each, any information relating to DTC, Cede & Co. or the book-entry only system, the financial, statistical and other information with respect to the Project Participant, and the other financial and statistical data included therein, as to all of which I express no view). In addition, nothing has come to my attention which would cause me to believe that it is unreasonable for the Underwriters to rely on the opinions they have received with respect to the Power Sales Agreement and the Agency Agreement rendered by counsel to the Project Participant.

Insofar as the foregoing opinions relate to the legal, valid and binding effect, and the enforceability, of any instrument, such opinions are subject to applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally, and are subject, as to enforceability, to general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law), to the exercise of judicial discretion in appropriate cases, and to the limitations on legal remedies against public agencies in the State of California. Also, a court may refuse to enforce a provision if it deems that such provision is in violation of public policy.

The opinions expressed herein are based upon the laws and other matters in effect on the date hereof. The opinions expressed are matters of professional judgment and are not a warranty or guarantee of result. I assume no obligation to revise or supplement this opinion letter should any law be changed by legislative action, judicial decision or otherwise, or should any facts or other matters upon which I have relied be changed.

The opinions which are set forth or which are expressed herein are limited to the laws of the State of California and the federal laws of the United States.

The opinions herein are furnished exclusively to the above recipients to whom this opinion letter is addressed. This opinion letter may not be provided to, made available to, or relied upon by any other party.

Respectfully submitted,

Christine Godinez
General Counsel
Southern California Public Power Authority

EXHIBIT C

CERTIFICATE OF SCPPA

I, [_____________], Executive Director of Southern California Public Power Authority ("SCPPA"), hereby certify as follows:

1. The representations and warranties of SCPPA contained in the Purchase Contract, dated _________, 2024 (the "Purchase Contract"), between SCPPA and J. P. Morgan Securities LLC, as representative (the "Representative") of the underwriters named therein, with respect to the sale by SCPPA of its Apex Power Project, Refunding Revenue Bonds, 2024 Series A, issued in the aggregate principal amount of $______________ (the "Bonds"), are true and correct in all material respects on and as of the date hereof as if made on this date.

2. As of the date hereof, except for any litigation (A) described or referred to in the Preliminary Official Statement of SCPPA, dated ___________, 2024, and in the Official Statement of SCPPA, dated _________, 2024, relating in each case to the Bonds, under the caption "LITIGATION" and the subcaption "LITIGATION" under the caption "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES" contained in APPENDIX A thereto, or (B) otherwise disclosed in writing to the Representative, there is no action, suit, proceeding, inquiry or investigation, at law or in equity before or by any court, government agency, public board or body, pending or, to the best of my knowledge, threatened against SCPPA (nor to the best of my knowledge is there any such action, suit, proceeding, inquiry or investigation pending or threatened against the Project Participant), affecting the existence of SCPPA or the titles of its officers to their respective offices, or affecting or seeking to prohibit, restrain or enjoin the sale, issuance or delivery of the Bonds or the collection of the Revenues of SCPPA pledged or to be pledged to pay the principal of and interest on the Bonds, or the pledge of and lien on the Revenues (as defined in the Indenture) or other funds and accounts established pursuant to the Indenture or contesting or affecting as to SCPPA the validity or enforceability of the Act, the SCPPA Organization Agreement, the Bonds, the Purchase Contract or any Basic Document, or contesting the tax-exempt status of interest on the Bonds for federal or State of California income tax purposes, or contesting the completeness or accuracy of the Preliminary Official Statement or the Official Statement or any supplement or amendment thereto, or contesting the powers of SCPPA or any authority for the issuance of the Bonds or the execution and delivery by SCPPA of the Purchase Contract or any Basic Document, or in any way contesting or challenging the consummation of the transactions contemplated thereby, or which might result in a material adverse change in the financial condition of SCPPA or which might materially adversely affect the generating capacity or output of the Apex Power Project (as defined in the Official Statement); nor, to the best of my knowledge, is there any basis for any such action, suit, proceeding, inquiry or investigation, wherein an unfavorable decision, ruling or finding would materially adversely affect the validity of the Act or the performance by SCPPA of the SCPPA Organization Agreement or the authorization, execution, delivery or performance by SCPPA of the Bonds, any Basic Document or the Purchase Contract.

3. To the best of my knowledge, no event affecting SCPPA or the Apex Power Project has occurred since the date of the Official Statement which should be disclosed in the Official Statement so that the Official Statement will not contain any untrue statement of a material fact or

omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading, and which has not been disclosed in a supplement or amendment to the Official Statement.

4. SCPPA has complied with all the agreements and satisfied all the conditions on its part to be performed or satisfied at or prior to the date hereof pursuant to the Purchase Contract with respect to the issuance of the Bonds.

All capitalized terms used herein which are not otherwise defined shall have the same meanings as in the Purchase Contract.

Dated: __________, 2024

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

____

[_____________]
Executive Director
Southern California Public Power Authority

EXHIBIT D

CERTIFICATE OF THE PROJECT PARTICIPANT

I, Ann M. Santilli, Chief Finance Officer of the Department of Water and Power of The City of Los Angeles (the "Department"), hereby certify on behalf of the Department as of the date hereof, that:

1. This certificate is furnished to the Underwriters pursuant to Section 9(e)(9) of the Purchase Contract, dated _________, 2024, between Southern California Public Power Authority ("SCPPA") and J. P. Morgan Securities LLC, as representative (the "Representative") of the underwriters named therein (the "Purchase Contract"), relating to the sale by SCPPA of $______________ in aggregate principal amount of its Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the "Bonds"), as more fully described in the Preliminary Official Statement of SCPPA, dated ___________, 2024 (the "Preliminary Official Statement") and the Official Statement of SCPPA, dated _________, 2024 (the "Official Statement"), prepared in connection with the sale of the Bonds.

2. To my knowledge, the ordinance of the City Council of the City of Los Angeles attached in Exhibit A hereto: (i) is in full force and effect; (ii) has not been amended, rescinded, supplemented or modified; and (iii) is not the subject of any actual or threatened, legal or administrative action by or before any court, commission, regulatory agency, arbitrator, mediator, negotiator, governmental entity (federal, state, municipal or other) or any other tribunal or body established to resolve disputes or enforce applicable constitutions, laws, ordinances, regulations, rules, customs or practices.

3. I have read the Preliminary Official Statement and the Official Statement and to my knowledge, but without having made an independent investigation, the Preliminary Official Statement as of its date and as of _________, 2024, and the Official Statement as of its date and as of the date hereof, including APPENDIX A thereto, as to matters known or made known to me relating to the Department, did not and does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements made therein, in the light of the circumstances under which they were made, not misleading.

4. The description of the business and properties of the power system of the Department included in the Preliminary Official Statement, including APPENDIX A thereto, as of its date and as of ___________, 2024, and in the Official Statement, including APPENDIX A thereto, as of the date of the Official Statement and as of the date hereof (in each case, including the data, schedules and statistics pertaining to the operations of the power system of the Department but excluding the financial statements, schedules and other financial data included therein), did not and does not contain an untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

5. The financial information regarding the power system of the Department contained in the Preliminary Official Statement and the Official Statement, including APPENDIX A thereto, fairly presents in all material respects the financial position and results of operations of such power

system as of the dates and for the periods set forth therein and, to the undersigned's knowledge, the financial statements of the power system of the Department included therein have been prepared in accordance with generally accepted accounting principles consistently applied and, except as otherwise indicated in the Preliminary Official Statement and the Official Statement, based upon the audited financial statements of the power system of the Department.

6. Other than as set, forth in the Preliminary Official Statement and the Official Statement, no litigation is pending against the Department with service of process against the Department having been made, or, to the knowledge of the undersigned, overtly threatened in writing in any way, (i) contesting or impairing the validity of the Power Sales Agreement or the Agency Agreement to which the Department is a party or the performance by the Department of the provisions thereof or involving the Department or its Power Assets (as defined in the City of Los Angeles City Charter) which would result in any material adverse change in the Power Revenue Fund (as defined in the City of Los Angeles City Charter) of the Department, other than routine litigation of the type which normally accompanies the construction and/or operation of municipal electric facilities.

7. The obligations of the Department to make payments under the Power Sales Agreement constitute a cost of purchased electricity and energy and an operating expense of the Department payable solely from its electric revenue fund.

8. The Department hereby acknowledges its obligation and agrees that, upon the occurrence of any of the following events with respect to the Department, the Department shall give notice of the occurrence of such event to SCPPA not later than five (5) business days after the occurrence of the event, together with all such information concerning such Financial Obligation (as defined below) of the Department, as may be necessary for SCPPA to satisfy its notice obligations under Resolution No. ___, adopted by the Board of Directors of SCPPA on ____, 2024, relating to the provision of certain continuing disclosure information with respect to the Bonds:

(i) incurrence of a Financial Obligation of the Department, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of the Department, any of which affect holders of the Bonds, if material; or

(ii) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Department, any of which reflect financial difficulties.

For purposes of this paragraph 8, the term “Financial Obligation” shall mean (a) a debt obligation; (b) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (c) guarantee of a debt obligation or any such derivative instrument; provided that “financial obligation” shall not include municipal securities as to which a final official statement (as defined in Rule 15c2-12 adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the “Rule”)) has been provided to the Municipal Securities Rulemaking Board consistent with the Rule.

10. The Department's Power Sales Agreement with SCPPA is in full force and effect, and neither the Department nor, to the best of my current actual knowledge, after due investigation, SCPPA, is in default of its obligations thereunder.

This Certificate is solely for the information of, and assistance to, SCPPA and the Underwriters in conducting and documenting their investigation of the matters covered by the Preliminary Official Statement and Official Statement in connection with the offering pursuant thereto, and is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of securities, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that references may be made to it in the Purchase Contract or in any list of closing documents pertaining to such offering.

All capitalized terms used herein shall have the meanings set forth in the Purchase Contract.

Dated: ___________, 2024

DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

By:____________________________
Ann M. Santilli
Chief Financial Officer

EXHIBIT E

[FORM OF ISSUE PRICE CERTIFICATE]

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

$______________

Apex Power Project, Refunding Revenue Bonds, 2024 Series A

UNDERWRITER'S CERTIFICATE

The undersigned, on behalf of J.P. Morgan Securities LLC (the "**Representative**"), on behalf of itself and PNC Capital Markets LLC (together with the Representative, the "**Underwriting Group**"), hereby certifies as set forth below with respect to the sale and issuance of the above-captioned obligations (the "**Bonds**").

[**Appropriate provisions to be selected based on results of sale of Bonds**]:

* * *

1. **Sale of the General Rule Maturities**. As of the date of this certificate, for each Maturity of the [General Rule Maturities/Bonds], the first price at which at least 10% of such Maturity of the Bonds was sold to the Public (the "Sale Price") is the respective price listed in Schedule A.

2. ***Initial Offering Price of the Hold-the-Offering-Price Maturities***.

(a) The Underwriting Group offered the [Hold-the-Offering-Price Maturities/Bonds] to the Public for purchase at the respective initial offering prices listed in Schedule A (the "Initial Offering Prices") on or before the Sale Date. A copy of the pricing wire or equivalent communication for the Bonds is attached to this certificate as Schedule B.]

(b) As set forth in the Purchase Contract for the Bonds, the members of the Underwriting Group have agreed in writing that, (i) for each Maturity of the Hold-the-Offering-Price Maturities, they would neither offer nor sell any of the Bonds of such Maturity to any person at a price that is higher than the Initial Offering Price for such Maturity during the Holding Period for such Maturity (the "**hold-the-offering-price rule**"), and (ii) any selling group agreement shall contain the agreement of each dealer who is a member of the selling group, and any retail distribution agreement shall contain the agreement of each broker-dealer who is a party to the retail distribution agreement, to comply with the hold-the-offering-price rule. Pursuant to such agreement, no Underwriter (as defined below) has offered or sold any Maturity of the Hold-the-Offering-Price Maturities at a price that is higher than the respective Initial Offering Price for that Maturity of the Bonds during the Holding Period.

[In lieu of (b) above: As set forth in the Purchase Contract for the Bonds, the Representative hereby elects to hold all unsold allotments of each of the Hold-the-Offering-Price Maturities during the Holding Period therefor. Representative will neither offer nor sell any of the Hold-the-

Offering-Price Maturities to any person at a price that is higher than the applicable Initial Offering Price for each of the Hold-the-Offering-Price Maturities during the Holding Period therefor.]

3. [***Issue Price***. The aggregate of the Sale Prices of the General Rule Maturities and the Initial Offering Prices of the Hold-the-Offering-Price Maturities is $[______] (the "Issue Price").]

4. ***Defined Terms***.

(a) [*General Rule Maturities* means those Maturities of the Bonds listed in Schedule A hereto as the "General Rule Maturities."]

(b) [*Hold-the-Offering-Price Maturities* means those Maturities of the Bonds listed in Schedule A hereto as the "Hold-the-Offering-Price Maturities."]

(c) [*Holding Period* means, with respect to a Hold-the-Offering-Price Maturity, the period starting on the Sale Date and ending on the earlier of (i) the close of the fifth business day after the Sale Date ([DATE]), or (ii) the date on which the Underwriters have sold at least 10% of such Hold-the-Offering-Price Maturity to the Public at prices that are no higher than the Initial Offering Price for such Hold-the-Offering-Price Maturity.]

(d) *Issuer* means Southern California Public Power Authority.

(e) *Maturity* means Bonds with the same credit and payment terms. Bonds with different maturity dates, or Bonds with the same maturity date but different stated interest rates, are treated as separate maturities.

(f) *Public* means any person (including an individual, trust, estate, partnership, association, company, or corporation) other than an Underwriter or a related party to an Underwriter. The term "related party" for purposes of this certificate generally means any two or more persons who have greater than 50 percent common ownership, directly or indirectly.

(g) *Sale Date* means the first day on which there is a binding contract in writing for the sale of a Maturity of the Bonds. The Sale Date of the Bonds is [DATE].

(h) *Underwriter* means (i) any person that agrees pursuant to a written contract with the Issuer (or with the lead underwriter to form an underwriting syndicate) to participate in the initial sale of the Bonds to the Public, and (ii) any person that agrees pursuant to a written contract directly or indirectly with a person described in clause (i) of this paragraph to participate in the initial sale of the Bonds to the Public (including a member of a selling group or a party to a retail distribution agreement participating in the initial sale of the Bonds to the Public).

5. **Yield**.

(a) **No Discount Maturities**. No Maturity was sold at an original issue discount.

(b) **Premium Maturities Subject to Optional Redemption**. The Maturities that mature in the year[s] 20__ are the only Maturities that are subject to optional redemption before maturity and have an Initial Offering Price or Sale Price, as applicable, that exceeds their stated redemption price at maturity by more than one fourth of 1% multiplied by the product of their stated redemption price at maturity and the number of complete years to their first optional redemption date. Accordingly, in computing the Yield on the Bonds stated below in paragraph [6(d)], each such Maturity was treated as retired on its optional redemption date or at maturity to result in the lowest yield on that Maturity. No Maturity is subject to optional redemption within five years of the Delivery Date of the Bonds.]

(c) **No Stepped Coupon Maturities**. No Maturity bears interest at an increasing interest rate.

(d) **Yield**. The Yield on the Bonds is [-]%, being the discount rate that, when used in computing the present worth of all payments of principal and interest to be paid on the Bonds, computed on the basis of a 360-day year and semi-annual compounding, produces an amount equal to the Issue Price of the Bonds as stated above in paragraph [-] [computed with the adjustments stated above in paragraph [-]].

6. **Weighted Average Maturity**. We have been asked to calculate the weighted average maturity of the Bonds in the following manner: divide (a) the sum of the products determined by taking the issue price of each maturity times the number of years from the date hereof to the date of such maturity (determined separately for each maturity and by taking into account mandatory redemptions), by (b) the aggregate issue price of such Bonds. Based solely on these calculations, the weighted average maturity of the Bonds is [-] years.

7. **Other Computations.** To the extent that we provided the Issuer and bond counsel with certain computations that show a bond yield, issue price, weighted average maturity and certain other information with respect to the Bonds, these computations are based on our normal application of standard industry software used for such purposes.

(signature page follows)

The representations set forth in this certificate are limited to factual matters and the accuracy of certain computations only. Nothing in this certificate represents the Representative's interpretation of any laws, including specifically Sections 103 and 148 of the Internal Revenue Code of 1986, as amended, and the Treasury Regulations thereunder. The undersigned understands that the foregoing information will be relied upon by the Issuer with respect to certain of the representations set forth in the Tax Certificate as to Arbitrage and the Provisions of Sections 141-150 of the Internal Revenue Code of 1986, and with respect to compliance with the federal income tax rules affecting the Bonds, and by Nixon Peabody LLP, Special Tax Counsel to the Issuer, in connection with rendering its opinion that the interest on the Bonds is excluded from gross income for federal income tax purposes, the preparation of Internal Revenue Service Form 8038-G, and other federal income tax advice it may give to the Issuer from time to time relating to the Bonds.

J.P. Morgan Securities LLC[, for itself and on behalf of the Underwriters]

By: ______________________________
Executive Director

SCHEDULE A

SALE PRICES OF THE GENERAL RULE MATURITIES AND

INITIAL OFFERING PRICES OF THE HOLD-THE-OFFERING-PRICE MATURITIES

(*Attached*)

SCHEDULE B

PRICING WIRE OR EQUIVALENT COMMUNICATION

(*Attached*)

EXHIBIT F

Opinion to the Underwriters of Special Tax Counsel

[Letterhead of Nixon Peabody LLP]

J. P. Morgan Securities LLC
[co-managers]
c/o J. P. Morgan Securities LLC
San Francisco, California

Re: Southern California Public Power Authority
Apex Power Project, Refunding Revenue Bonds, 2024 Series A

Ladies and Gentlemen:

This letter is delivered to you, as underwriters, pursuant to Section 8(e)(6) of the Purchase Contract, dated __________, 2024 (the "Purchase Contract"), between J. P. Morgan Securities LLC, as your representative, and Southern California Public Power Authority (the "Authority").

We deliver herewith a copy of our opinion, dated the date hereof and addressed to the Authority, as to certain tax matters pertaining to the Authority's Apex Power Project, Revenue Bonds, 2024 Series A, issued in the aggregate principal amount of $_______________ and Apex Power Project, Revenue Bonds, 2024 Series B (Federally Taxable)(collectively, the "Bonds"). This will confirm that you may rely upon such opinion as if the same were addressed to you.

We are of the opinion that the statements in the Preliminary Official Statement and the Official Statement under the caption "TAX MATTERS", Appendix F –"PROPOSED FORMS OF SPECIAL TAX COUNSEL OPINION", and in the first paragraph of the cover of the Preliminary Official Statement and Official Statement, to the extent such statements purport to summarize certain provisions of federal or state tax law, are fair and accurate summaries of such provisions.

We are furnishing you this letter at the request of the Authority and solely for the information of, and assistance to, you in conducting and documenting your investigation of the affairs of the Authority in connection with the offering of the Bonds and it is not to be used, circulated, quoted or otherwise referred to for any other purpose, including but not limited to the purchase or sale of the Bonds, nor is it to be referred to in whole or in part in the Preliminary Official Statement or the Official Statement or any other document, except that it may be included in, and reference may be made to it in any list of, the closing documents pertaining to the delivery of the Bonds. The provision of this opinion letter to you shall not create any attorney-client relationship between either of our firms and you. This opinion letter may not be relied upon by any other person, firm, corporation or other entity without our prior written consent, and we have no obligation to update this opinion.

Very truly yours,

PRELIMINARY OFFICIAL STATEMENT DATED __________, 2024

NEW ISSUE – FULL BOOK-ENTRY ONLY

Ratings: S&P: "[___]"
Fitch: "[___]"
(See "RATINGS" herein)

In the opinion of Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel, under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by the Authority described herein, interest on the 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code. Special Tax Counsel is further of the opinion that interest on the 2024 Series A Bonds is exempt from personal income taxes of the State of California (the "State") under present State law. See "TAX MATTERS" herein regarding certain other tax considerations.

$________*

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

(a public entity organized under the laws of the State of California)

Apex Power Project, Refunding Revenue Bonds,
2024 Series A

Dated: Date of Delivery | Due: July 1, as shown on inside cover

This cover page contains certain information for general reference only. It is not intended to be a summary of the security for or terms of this issue. Investors are advised to read the entire Official Statement to obtain information essential to making an informed investment decision. Capitalized terms used on this cover page not otherwise defined shall have the meanings set forth herein.

The Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the "2024 Series A Bonds") are being issued by the Southern California Public Power Authority (the "Authority") pursuant to an Indenture of Trust, dated as of March 1, 2014, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), as supplemented and amended (the "Indenture").

The 2024 Series A Bonds are being issued to provide funds to (i) provide funds to refund and redeem all or a portion of the Authority's outstanding Apex Power Project, Revenue Bonds, 2014 Series A (the "2014 Series A Bonds") outstanding in the aggregate principal amount of $_______ and all or a portion of the Authority's outstanding Apex Power Project, Revenue Bonds, 2014 Series B (Federally Taxable) (the "2014 Series B Bonds" and, together with the 2014 Series A Bonds, the "Refunded Bonds") outstanding in the aggregate principal amount of $_______ and (ii) pay the costs of issuance relating to the 2024 Series A Bonds. See "REFUNDING PLAN" herein.

The Apex Power Project consists of a natural gas-fired, combined cycle generating facility, nominally-rated at 531 MW, located in Clark County, Nevada, generator interconnection facilities, other related assets and property, and interconnection and transmission contractual rights. The Apex Power Project was acquired by the Authority pursuant to an Asset Purchase Agreement, dated as of October 17, 2013 (the "Asset Purchase Agreement"), by and between the Authority and Las Vegas Power Company, LLC, for the primary purpose of providing the Department of Water and Power of The City of Los Angeles (the "Department" or the "Project Participant") with energy and base-load, combined cycle, gas-fired generating capacity. The Department is the only Project Participant of the Authority in the Apex Power Project. See "THE APEX POWER PROJECT" herein.

The 2024 Series A Bonds will be issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository of the 2024 Series A Bonds. Purchasers of the 2024 Series A Bonds will not receive physical certificates representing their interest in the 2024 Series A Bonds purchased. Individual purchases of the 2024 Series A Bonds will be made in book-entry form only, in denominations of $5,000 principal amount or any integral multiple thereof. Interest on the 2024 Series A Bonds is payable semiannually on January 1 and July 1 of each year, commencing July 1, 2024. Principal of, premium, if any, and interest on, the 2024 Series A Bonds are payable directly to DTC by the Trustee. Upon receipt of payments of such principal, premium, if any, and interest, DTC is obligated to remit such principal, premium, if any, and interest to its DTC participants for subsequent disbursement to the beneficial owners of the 2024 Series A Bonds. See "BOOK-ENTRY ONLY SYSTEM" herein.

The 2024 Series A Bonds are subject to redemption prior to maturity as described herein.

The 2024 Series A Bonds are special limited obligations of the Authority payable solely from and secured solely by a pledge and assignment of Revenues and certain other moneys described herein. Revenues consist primarily of payments to be made to the Authority by the Department, as Project Participant, pursuant to a Power Sales Agreement, by and between the Authority and the Project Participant, as described herein. Pursuant to the Power Sales Agreement, the Authority has sold all the Facility Output of the Apex Power Project to the Project Participant, and the Project Participant has agreed to pay to the Authority, solely from its electric system revenues, Monthly Power Costs therefor, including, among other things, all operating costs, fuel costs and Indenture costs (including debt service costs on the 2024 Series A Bonds) of the Authority in connection with the Apex Power Project. Pursuant to the Power Sales Agreement, such payments to be made by the Project Participant will constitute operating expenses of the Apex Power Project Participant's electric system. The payment obligations of the Project Participant under the Power Sales Agreement are not contingent upon the operation of the Apex Power Project or the performance or nonperformance by any party of any agreement for any cause whatsoever. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A BONDS" herein.

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* Preliminary, subject to change.

The Authority has reserved its right to issue additional parity bonds under the Indenture and to enter into Parity Swaps on the terms and conditions and for the purposes stated in the Indenture.

The 2024 Series A Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), the Project Participant or any other member of the Authority and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024 Series A Bonds. The Authority has no taxing power.

Maturity Schedules
(see inside cover)

The 2024 Series A Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel, and certain other conditions. Certain legal matters will be passed on for the Authority by its General Counsel, Christine Godinez, Esq. and by Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel, and for the Underwriters by their counsel, Hawkins Delafield & Wood LLP, Sacramento, California. PFM Financial Advisors LLC is serving as Municipal Advisor to the Authority in connection with the issuance of the 2024 Series A Bonds. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2024 Series A Bonds. It is expected that the 2024 Series A Bonds will be available for delivery through the facilities of DTC in New York, New York, by Fast Automated Securities Transfer (FAST) on or about ______, 2024.

J.P. Morgan **PNC Capital Markets LLC**

Dated : ___________, 2024

Maturity Schedules*

$_________
Apex Power Project, Refunding Revenue Bonds, 2024 Series A

Due July 1	Principal Amount	Interest Rate	Yield	Price	CUSIP†
	$	%	%		

$__________
Apex Power Project, Refunding Revenue Bonds, 2024 Series B (Federally Taxable)

Due July 1	Principal Amount	Interest Rate	Yield	Price	CUSIP†
	$	%	%		

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* Preliminary, subject to change.

† CUSIP® is a registered trademark of the American Bankers Association. CUSIP data herein are provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of the American Bankers Association. CUSIP numbers have been assigned by an independent company not affiliated with the Authority and are included solely for the convenience of the holders of the 2024 Series A Bonds. None of the Authority, its Municipal Advisor or the Underwriters is responsible for the selection or use of these CUSIP numbers and no representation is made as to their correctness on the 2024 Series A Bonds or as indicated above. The CUSIP number for a specific bond is subject to being changed after the issuance of the bonds as a result of various subsequent actions including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of such bonds.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PROJECT PARTICIPANT

Department of Water and Power of The City of Los Angeles

MUNICIPAL ADVISOR

PFM Financial Advisors LLC
Los Angeles, California

BOND COUNSEL AND DISCLOSURE COUNSEL

Norton Rose Fulbright US LLP
Los Angeles, California

SPECIAL TAX COUNSEL

Nixon Peabody LLP
Los Angeles, California

TRUSTEE AND PAYING AGENT

U.S. Bank Trust Company, National Association
Los Angeles, California

No dealer, broker, salesperson or other person has been authorized by the Authority or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Authority or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 2024 Series A Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

This Official Statement is not to be construed as a contract with the purchasers of the 2024 Series A Bonds. Statements contained in this Official Statement that involve estimates, forecasts or matters of opinion, whether or not expressly described herein, are intended solely as such and are not to be construed as representations of fact.

The information set forth herein has been furnished by the Authority and certain of the Department, and includes information obtained from other sources which are believed to be reliable. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Project Participant since the date hereof.

The Underwriters have provided the following two paragraphs for inclusion in this Official Statement:

The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

IN CONNECTION WITH THE OFFERING OF THE 2024 SERIES A BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICES OF THE 2024 SERIES A BONDS AT LEVELS ABOVE THOSE WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

Certain statements included or incorporated by reference in this Official Statement constitute "forward-looking statements." Such statements are generally identifiable by the terminology used such as "plan," "project," "expect," "anticipate," "intend," "believe," "estimate," "budget" or other similar words. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements described to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. The Authority does not plan to issue any updates or revisions to those forward-looking statements if or when its expectations or events, conditions or circumstances on which such statements are based occur or fail to occur.

This Official Statement, including any supplement or amendment hereto, is intended to be filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Market Access (EMMA) website. The Authority and the Department also maintain websites. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2024 Series A Bonds.

References to website addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader's convenience. Unless specified otherwise, such websites and the information or links contained therein are not incorporated into, and are not part of, this Official Statement for purposes of, and as that term is defined in, SEC Rule 15c2-12.

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(continued)

Official Statement
relating to

$_________*
Southern California Public Power Authority
(a public entity organized under the laws of the State of California)
Apex Power Project, Refunding Revenue Bonds,
2024 Series A

INTRODUCTION

This Introduction is subject in all respects to the more complete information contained elsewhere in this Official Statement, and the offering of the 2024 Series A Bonds (as defined herein) to potential investors is made only by means of the entire Official Statement. Capitalized terms used in this Introduction and not defined herein shall have the respective meanings assigned to them elsewhere in this Official Statement or in the hereinafter-referenced Indenture or Power Sales Agreement. See also APPENDIX B – "SUMMARIES OF CERTAIN DOCUMENTS."

Purpose; Authority for Issuance

This Official Statement (which includes the cover page, the table of contents and the appendices attached hereto) is furnished by the Southern California Public Power Authority (the "Authority"), a joint powers agency and a public entity organized under the laws of the State of California, to provide information concerning the Apex Power Project described herein, the $__________* aggregate principal amount of Apex Power Project, Refunding Revenue Bonds, 2024 Series A (the "2024 Series A Bonds") to be issued by the Authority. The 2024 Series A Bonds are being issued pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), and an Indenture of Trust, dated as of March 1, 2014 (the "Indenture of Trust"), from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), as previously supplemented and as supplemented by the Third Supplemental Indenture of Trust, dated as of June 1, 2024, from the Authority to the Trustee providing for the issuance of the 2024 Series A Bonds (the "Third Supplemental Indenture"). The Indenture of Trust, as so supplemented and amended, is herein referred to as the "Indenture."

The 2024 Series A Bonds are being issued to provide funds to (i) provide funds to refund and redeem all of the Authority's outstanding Apex Power Project, Revenue Bonds, 2014 Series A (the "2014 Series A Bonds") outstanding in the aggregate principal amount of $_______ and all of the Authority's outstanding Apex Power Project, Revenue Bonds, 2014 Series B (Federally Taxable) (the "2014 Series B Bonds" and, together with the 2014 Series A Bonds, the "Refunded Bonds") outstanding in the aggregate principal amount of $_______ and (ii) pay the costs of issuance relating to the 2024 Series A Bonds. See "REFUNDING PLAN."

The Project

General Description.

The Apex Power Project consists of a natural gas-fired, combined cycle generating facility, nominally rated at 531 megawatts ("MW"), located in Clark County, Nevada, and generator interconnection

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* Preliminary, subject to change.

facilities (collectively, the "Facility"), related assets and property and interconnection and transmission contractual rights (the "Apex Power Project" or the "Project").

The Apex Power Project was acquired by the Authority pursuant to an Asset Purchase Agreement, dated as of October 17, 2013 (the "Asset Purchase Agreement"), by and between the Authority and Las Vegas Power Company, LLC (the "Seller"), for the primary purpose of providing the Department of Water and Power of The City of Los Angeles (the "Department" or the "Project Participant") with energy and base-load, combined cycle, gas-fired generating capacity. The Department is the only Project Participant of the Authority in the Apex Power Project. See "THE APEX POWER PROJECT" herein.

Operation and Maintenance Agreement. The Facility is operated by EthosEnergy Power Operations (West) LLC ("EthosEnergy") (formerly Wood Group Power Operations (West), Inc. ("Wood Group")) pursuant to an Operations and Maintenance Agreement, initially between the Seller and Wood Group, dated February 12, 2007, as amended, and assumed and further amended by the Authority (the "O&M Agreement") pursuant to the Asset Purchase Agreement. Under the O&M Agreement, EthosEnergy provides all operations, routine maintenance, budget control, purchasing, billing, and reporting for the operation of the Facility, other than the maintenance provided by General Electric International Inc. ("GEI") under the Long-Term Service Agreement discussed below. EthosEnergy, as part of its preventative maintenance, performs, among other things, lube oil and transformer oil analysis, vibration analysis on rotating equipment, and thermal-imaging on both the electrical equipment and the heat recovery steam generators. The O&M Agreement expires on February 12, 2028. EthosEnergy has served as the operator of the Facility since it achieved commercial operation in 2003.

Long-Term Service Agreement. Major maintenance, including parts supply, parts repair and labor for the Facility's combustion turbine generators and the steam turbine are provided pursuant to a Long-Term Service Agreement between the Authority and GEI, dated June 16, 2004, as amended (the "LTSA"). The LTSA expires with respect to each gas turbine on the later of the following: (i) the later of (a) the date on which a gas turbine accrues 112,000 actual Factored Fired Hours (as defined in the LTSA) or (b) 3,600 Factored Starts (as defined in the LTSA), and (ii) the date of completion of the fourth Hot Gas Path (as defined in the LTSA) inspection. The LTSA expires with respect to the steam turbine on the date that the LTSA has expired with respect to either of the gas turbines. It is not possible to determine when the LTSA will expire. The Department currently anticipates that the LTSA will expire in 2024. The Department, as the Project Manager, will administer, supervise, monitor and enforce the O&M Agreement and the LTSA in accordance with the Agency Agreement.

For additional information regarding the Project, see "THE APEX POWER PROJECT."

See also "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of Agency Agreement" in Appendix B hereto.

Power Sales Agreement

General; Unconditional Payment Obligation. Pursuant to the Power Sales Agreement, the Department has acquired an Output Entitlement to 100% of the capacity and energy of the Facility. The Authority sold to the Department and the Department purchased from the Authority all of the Facility Output. The Department is obligated to pay for such capacity and energy on a "take-or-pay" basis, that is, whether or not the Project or any part thereof is functioning, producing, operating or operable or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance by any party of any agreement for any cause whatsoever. Monthly Power Costs (as defined below) payments required to be made by the Department under the Power Sales

Agreement in consideration for its Output Entitlement include an operating cost component, a fuel cost component, an Indenture cost component (including debt service costs on Bonds (including the 2024 Series A Bonds) issued by the Authority to finance or refinance the Project and other amounts required to be deposited into the funds and accounts established under the Indenture) and a supplementary services cost component of the Project (*i.e.*, in each case, 100% of such costs), each as described herein under "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A BONDS – Power Sales Agreement – *Monthly Power Costs*." The payment obligations of the Department under the Power Sales Agreement constitute operating expenses of the Department's electric system, payable solely from its electric revenue fund, including any legally available electric power system reserves. As an operating expense of its electric system, the payment obligations of the Department under the Power Sales Agreement and all other of its "take-or-pay" contract obligations are payable on a parity with the Department's electric system revenue bonds. See APPENDIX A – "THE PROJECT PARTICIPANT – THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES." See also "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A BONDS – Power Sales Agreement" and "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Power Sales Agreement" in Appendix B hereto.

Payment Default; Termination of Rights in the Project. In the event the Department fails to begin to cure a Payment Default within approximately two months or fails to fully cure a Payment Default within approximately five months from its Initial Payment Default Date and fails to timely provide the Authority with a Suspension Request Notice (as described in the Power Sales Agreement), the Department's Project Rights (including its entitlements to Facility Output) will be immediately and permanently discontinued and terminated and its Project Rights and Obligations (as defined in the Power Sales Agreement) will be disposed of by the Authority, and the Authority will offer to convey, transfer and assign such Project Rights and Obligations, first, to all the requesting members of the Authority and then to third parties, subject to the terms of the Power Sales Agreement. If all such Project Rights and Obligations are not so conveyed, transferred and assigned, the Authority will use its best efforts, to the extent reasonably possible and economically beneficial, to sell the remaining Facility Output, for long-term or short-term sales, on the best terms readily available pursuant to the terms and conditions established by the Authority and subject to the terms of the Power Sales Agreement. So long as any Bonds are Outstanding under the Indenture, the Department's obligation to make payments under the Power Sales Agreement shall not be eliminated or reduced upon a termination of the Department's rights in the Project as described herein, except to the extent of moneys received by the Authority as a result of the conveyance, transfer and assignment of such Project Rights and Obligations, less the Authority's related costs and expenses. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A BONDS – Power Sales Agreement – *Participant's Failure to Pay Billing Statement*" and "– *Termination and Disposal of Project Rights*."

The Authority

The Authority, the membership of which is comprised of eleven California cities and one California irrigation district, was formed pursuant to the Act and the Joint Powers Agreement, dated as of November 1, 1980 (as amended, the "Joint Powers Agreement"). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Formation" herein.

For additional information concerning the Authority and its activities, see "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY." For additional information regarding the Department, see APPENDIX A – "THE PROJECT PARTICIPANT – THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES."

Security and Sources of Payment for the 2024 Series A Bonds

The principal of and premium, if any, and interest on the 2024 Series A Bonds are payable solely from and secured solely by a pledge and assignment of Revenues (as defined below) and certain other moneys described herein. Revenues consist primarily of payments to be made to the Authority by the Department, as the Project Participant, pursuant to the Power Sales Agreement. The Department has agreed to make such payments solely from its electric system revenues, and such payments constitute operating expenses of its electric system. The payment obligations of the Department under the Power Sales Agreement are not contingent upon the operation of the Project or the performance or nonperformance by any party under any agreement for any cause whatsoever.

The 2024 Series A Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), the Project Participant or any other member of the Authority, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024 Series A Bonds. The Authority has no taxing power.

Outstanding Bonds; Other Obligations

Assuming the issuance of the 2024 Series A Bonds and the defeasance or redemption of the Refunded Bonds, the only outstanding Authority bonds relating to the Apex Power Project will be the 2024 Series A Bonds.

The Authority has reserved its right to issue additional parity bonds or other parity obligations under the Indenture and to enter into Parity Swaps on the terms and conditions and for the purposes stated in the Indenture. The 2024 Series A Bonds and any other bonds, notes or other evidence of indebtedness hereafter issued pursuant to the Act and the Indenture on parity with the 2024 Series A Bonds are herein collectively referred to as the "Bonds."

Continuing Disclosure Undertaking

Pursuant to a resolution of the Authority's Board of Directors adopted on [____], 2024 (the "Continuing Disclosure Resolution"), the Authority has agreed for the benefit of the registered owner and the "Beneficial Owners" (as defined in the Continuing Disclosure Resolution) of the 2024 Series A Bonds to provide certain financial information and operating data and to provide notices of certain events. See "CONTINUING DISCLOSURE UNDERTAKING FOR THE 2024 SERIES A BONDS."

Certain Information; Summaries and References to Documents

In preparing this Official Statement, the Authority has relied upon information relating to the Department provided to the Authority by the Department. This Official Statement also includes summaries of certain terms of the 2024 Series A Bonds, the Indenture, the Power Sales Agreement, the Agency Agreement and the Asset Purchase Agreement, and certain contracts and arrangements relating to the Project. The summaries of and references to all documents, agreements, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, agreement, statute, report or instrument.

REFUNDING PLAN

The 2024 Series A Bonds are being issued to provide funds, together with certain other available amounts, to (i) refund all of the 2014 Series A Bonds outstanding in the aggregate principal amount of

$151,880,000 and all of the 2014 Series B Bonds outstanding in the aggregate principal amount of $78,155,000 and (ii) pay costs of issuance relating to the 2024 Series A Bonds.

The outstanding 2014 Series A Bonds and 2014 Series B Bonds are set forth in the respective tables below.

2014 Series A Bonds

Maturity Date	Principal Amount	Interest Rate	CUSIP†
July 1, 2030	$10,015,000	5.000%	84247PHF1
July 1, 2031	14,855,000	5.000	84247PHG9
July 1, 2032	15,600,000	5.000	84247PHH7
July 1, 2033	16,380,000	5.000	84247PHJ3
July 1, 2034	17,200,000	5.000	84247PHK0
July 1, 2035	18,055,000	5.000	84247PHL8
July 1, 2036	18,960,000	5.000	84247PHM6
July 1, 2037	19,910,000	5.000	84247PHN4
July 1, 2038	20,905,000	5.000	84247PHP9

† CUSIP® is a registered trademark of American Bankers Association. CUSIP® data herein are provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of American Bankers Association. None of the Authority, its Municipal Advisor or the Underwriters is responsible for the selection or correctness of the CUSIP numbers set forth herein.

2014 Series B Bonds

Maturity Date	Principal Amount	Interest Rate	CUSIP†
July 1, 2024	$11,205,000	3.608%	84247PHZ7
July 1, 2025	11,610,000	3.758	84247PJA0
July 1, 2026	12,045,000	3.938	84247PJB8
July 1, 2027	12,520,000	4.108	84247PJC6
July 1, 2028	13,035,000	4.208	84247PJD4
July 1, 2029	13,585,000	4.308	84247PJE2
July 1, 2030	4,155,000	4.408	84247PJF9

† CUSIP® is a registered trademark of American Bankers Association. CUSIP® data herein are provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of American Bankers Association. None of the Authority, its Municipal Advisor or the Underwriters is responsible for the selection or correctness of the CUSIP numbers set forth herein.

The Refunded Bonds were issued on March 26, 2014. Proceeds of the Refunded Bonds were used to pay the costs of acquisition by the Authority of the Apex Power Project, and the costs of certain replacement parts for, capital improvements to, and insurance and other initial costs for, the Apex Power Project (as described herein) following its acquisition by the Authority, fund a debt service reserve fund and pay the costs of issuance relating to the Refunded Bonds.

The refunding of the Refunded Bonds will be effected by depositing a portion of the proceeds of the 2024 Series A Bonds and certain moneys provided by the Authority into an escrow fund (the "Escrow Fund") pursuant to the terms of the Third Supplemental Indenture. The moneys in the Escrow Fund will either be held as cash or will be used to purchase Defeasance Obligations (as defined in the Indenture) that will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their respective terms (without reinvestment), and together with any cash held in the Escrow Fund, sufficient moneys will be available to pay on July 1, 2024 the principal of the Refunded Bonds maturing on July 1, 2024, together with accrued interest to such date, and to pay on [July 1], 2024 the redemption price of the Refunded Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, together with accrued interest to the redemption date.

Upon such deposits and investment and compliance with certain notice requirements set forth in the Indenture, the liability of the Authority with respect to the Refunded Bonds will cease and the Refunded Bonds will no longer be outstanding under the Indenture, except that the Owners of the Refunded Bonds will be entitled to payment thereof solely from the amounts on deposit in the Escrow Fund.

On the date of delivery of the 2024 Series A Bonds, the Authority will receive reports from [_________] verifying (i) the adequacy of the principal amounts of the Defeasance Obligations on deposit in the Escrow Fund, together with certain other available amounts, if any, and interest income earned on such Defeasance Obligations, to pay on July 1, 2024 the principal of the Refunded Bonds maturing on July 1, 2024, together with accrued interest to such date, and to pay on [July 1], 2024 the redemption price of the Refunded Bonds maturing on July 1, 2025 through July 1, 2038, inclusive, together with accrued interest to the redemption date. See "VERIFICATION OF MATHEMATICAL COMPUTATIONS."

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds relating to the 2024 Series A Bonds are shown below:

Sources:	
Principal Amount	$
Original Issue Premium	
[Transfer from Participating Bonds Debt Service Reserve Account]	
Total Sources	$
Uses:	
Deposit to Escrow Fund	$
Costs of Issuance[(1)]	
Total Uses	$

[(1)] Includes, among other things, Underwriters' discount, Trustee's fees, Bond Counsel fees, Disclosure Counsel fees, Special Tax Counsel fees, verification agent fees, Municipal Advisor fees and rating agencies fees.

DEBT SERVICE REQUIREMENTS

The debt service requirements for the Bonds are set forth in Appendix F hereto.

DESCRIPTION OF THE 2024 SERIES A BONDS

General

The 2024 Series A Bonds will be issued as fully registered bonds in the denomination of $5,000 principal amount and any integral multiple thereof. The 2024 Series A Bonds will be issued in the respective aggregate principal amounts indicated on the cover page of this Official Statement and will be dated their date of delivery. The 2024 Series A Bonds will bear interest at the respective rates per annum and will mature on July 1 in the respective years and in the respective principal amounts set forth on the inside cover page of this Official Statement. Interest on the 2024 Series A Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2024, and will be calculated on the basis of a 360-day year comprised of twelve 30-day months.

The 2024 Series A Bonds when initially issued will be registered in the name of Cede & Co., as registered owner and nominee of The Depository Trust Company, New York, New York ("DTC"). So long as DTC, or its nominee Cede & Co., is the registered owner of all the 2024 Series A Bonds, all payments of principal of and premium, if any, and interest on such 2024 Series A Bonds will be made directly to DTC. Disbursement of such payments to the DTC participants will be the responsibility of DTC. Disbursement of such payments to the applicable Beneficial Owners (as defined below) of the 2024 Series A Bonds will be the responsibility of the DTC participants as more fully described herein. See "BOOK-ENTRY ONLY SYSTEM" below.

Redemption Provisions

Optional Redemption of 2024 Series A Bonds. The 2024 Series A Bonds are subject to redemption prior to maturity, at the option of the Authority, from any source of available funds, in whole or in part (and, if in part, from such maturities as the Authority shall direct), on any date on or after July 1, 20__, at a Redemption Price equal to the principal amount of the 2024 Series A Bonds, or portions thereof, to be redeemed, without premium, in each case together with accrued interest to the redemption date.

Selection of 2024 Series A Bonds to be Redeemed. Whenever by the terms of the Indenture, 2024 Series A Bonds are to be redeemed at the direction of the Authority, the Authority shall select the maturity or maturities of 2024 Series A Bonds to be redeemed. If less than all of the 2024 Series A Bonds of a maturity are called for prior redemption, the particular 2024 Series A Bonds or portions of such maturity to be redeemed shall be selected by lot; provided, however, that the portion of any 2024 Series A Bond of a denomination of more than $5,000 to be redeemed shall be in the principal amount of $5,000 or a multiple thereof, and in selecting portions of such 2024 Series A Bonds for redemption, the Trustee shall treat each such 2024 Series A Bond as representing that number of 2024 Series A Bonds of $5,000 denomination that is obtained by dividing the principal amount of such 2024 Series A Bonds to be redeemed in part by $5,000.

Notice of Redemption. The Indenture requires the Trustee to give notice of any redemption of the 2024 Series A Bonds to the Owners of any 2024 Series A Bonds designated for redemption by mail not less than 30 nor more than 60 days prior to the redemption date. If by the date of mailing of notice of any optional redemption the Authority has not deposited with the Trustee moneys sufficient to redeem all the 2024 Series A Bonds called for redemption, such notice will state that it is subject to the availability of funds for such purpose and will be of no effect unless funds sufficient for such purpose are available on the applicable redemption date. Failure by any one or more of the Owners of any of the 2024 Series A Bonds designated for redemption to receive notice of redemption, or any defect in any such notice will not affect the validity of the proceedings for the redemption of such 2024 Series A Bond.

Effect of Redemption. Notice having been given in the manner provided in the Indenture, and moneys sufficient therefor having been deposited by the Authority with the Trustee, the 2024 Series A Bonds or portions thereof so called for redemption shall become due and payable on the redemption date so designated at the redemption price, plus interest accrued and unpaid to the redemption date, and, upon presentation and surrender thereof at the office specified in such notice, such 2024 Series A Bonds, or portions thereof, shall be paid at the redemption price, plus interest accrued and unpaid to the redemption date. If, on the redemption date, moneys for the redemption of all the 2024 Series A Bonds or portions thereof to be redeemed, together with interest to the redemption date, shall be held by the Trustee so as to be available therefor on said date and if notice of redemption shall have been given as aforesaid, then, from and after the redemption date, interest on the 2024 Series A Bonds or portions thereof so called for redemption shall cease to accrue and shall become payable. If said moneys shall not be so available on the redemption date, such 2024 Series A Bonds or portions thereof shall continue to bear interest.

BOOK-ENTRY ONLY SYSTEM

General

DTC will act as securities depository for the 2024 Series A Bonds. The 2024 Series A Bonds will be issued as fully registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered 2024 Series A Bond certificate will be issued for each maturity of the 2024 Series A Bonds in the aggregate principal amount of such maturity, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to DTC's participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com. The information on such website is not incorporated herein by reference.

Purchases of the 2024 Series A Bonds under the DTC book-entry system must be made by or through Direct Participants, which will receive a credit for the 2024 Series A Bonds on DTC's records. The ownership interest of each actual purchaser of each 2024 Series A Bonds ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2024 Series A Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2024 Series A Bonds, except in the event that use of the book-entry system for the 2024 Series A Bonds is discontinued.

To facilitate subsequent transfers, all 2024 Series A Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of 2024 Series A Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2024 Series A Bonds. DTC's records reflect only the identity of the Direct Participants to whose accounts such 2024 Series A Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of the 2024 Series A Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2024 Series A Bonds, such as redemptions, defaults and proposed amendments to the Indenture. For example, Beneficial Owners of 2024 Series A Bonds may wish to ascertain that the nominee holding the 2024 Series A Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the Bond Registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of a maturity of the 2024 Series A Bonds of an issue are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to 2024 Series A Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Authority as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts 2024 Series A Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal, redemption price and interest payments on the 2024 Series A Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Authority or the Trustee, on each payment date in accordance with their respective holdings shown on DTC's records. Payments by Direct and Indirect Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such participant and not of DTC, the Trustee or the Authority, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal, redemption price and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Authority or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to Beneficial Owners is the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2024 Series A Bonds at any time by giving reasonable notice to the Authority or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, the 2024 Series A Bonds certificates are required to be printed and delivered.

The Authority may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, the 2024 Series A Bonds certificates will be printed and delivered.

The foregoing description concerning DTC and DTC's book-entry system is based solely on information furnished by DTC. No representation is made herein by the Authority or the Underwriters as to the accuracy or completeness of such information, and the Authority and the Underwriters take no responsibility for the accuracy or completeness thereof.

Discontinuation of the Book-Entry Only System

If DTC determines not to continue to act as securities depository by giving notice to the Authority and the Trustee, and discharges its responsibilities with respect thereto under applicable law and there is not a successor securities depository, or the Authority determines not to continue the book-entry system through a securities depository, the Authority and the Trustee will cause the delivery of definitive 2024 Series A Bonds to the Beneficial Owners of the 2024 Series A Bonds registered in the names of such Beneficial Owners as shall be specified to the Trustee by DTC.

If the book-entry system is discontinued the following provisions would apply: (i) the principal and redemption price, if any, of the 2024 Series A Bonds will be payable upon surrender of such 2024 Series A Bond at the principal corporate trust office of the Trustee (as paying agent for the 2024 Series A Bonds) and at the office of any other paying agent hereafter appointed by the Authority; (ii) interest on the 2024 Series A Bonds will be payable by check of the Trustee mailed by first-class mail, postage prepaid, on the applicable interest payment date to the Owner thereof at his or her address shown on the registration books maintained by the Trustee as of the 15th day of the calendar month immediately preceding such interest payment date (the "Record Date") or in immediately available funds by wire transfer on the interest payment date to a designated account, if payable to any Owner of a 2024 Series A Bond or Bonds in an aggregate principal amount of $1,000,000 or more, upon written request of such Owner to the Trustee received by the Trustee prior to the Record Date for the first interest payment date as to which such request shall be effective, specifying the account or accounts to which such payment shall be made (which request shall remain in effect until revoked or reversed by such Owner in a subsequent writing delivered to the Trustee); (iii) the transfer of any 2024 Series A Bond shall be registrable only upon the books of the Authority, which shall be kept for such purposes at the principal corporate trust office of the Trustee, as bond registrar, by the Owner thereof in person or by his or her attorney duly authorized in writing, upon surrender of such 2024 Series A Bond, together with a written instrument of transfer satisfactory to the bond registrar duly executed by the Owner or his or her duly authorized attorney, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such registration of transfer; (iv) 2024 Series A Bonds may be exchanged for an equal aggregate principal amount of 2024 Series A Bonds of the same tenor, maturity and interest rate in such other authorized denomination or denominations as shall be requested by such Owner, upon surrender of such 2024 Series A Bonds at the principal corporate trust office of the Trustee, as bond registrar, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange; and (v) the Trustee (as bond registrar for the 2024 Series A Bonds) will not be required to register the transfer of, or exchange, any 2024 Series A Bonds called for redemption, or any 2024 Series A Bonds during the period of 15 days next preceding any selection of 2024 Series A Bonds to be redeemed (if applicable).

SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A BONDS

Pledge Effected by the Indenture

The Indenture provides that the 2024 Series A Bonds and any other Bonds issued thereunder shall be special, limited obligations of the Authority payable solely from and secured, as to payment of the principal or Redemption Price thereof, and interest thereon, solely by (i) the proceeds of the sale of the

Bonds, including the 2024 Series A Bonds, (ii) the Revenues and (iii) all amounts on deposit in any Fund or Account established by the Indenture (except for such Funds and Accounts, including the Decommissioning Fund, that the Indenture provides are not a source of payment for the Bonds, including the 2024 Series A Bonds, or any Parity Swaps and other than any funds held by the Trustee or the Authority to pay any rebate amount owed to the federal government) including the investments, if any, thereof, and the same are pledged and assigned pursuant to the Indenture, subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture, as security for the payment of the Bonds, including the 2024 Series A Bonds, the interest thereon, and premium, if any, with respect thereto, as security for the payment obligations of the Authority under any Parity Swaps and as security for the performance of any other obligations of the Authority under the Indenture, all in accordance with the provisions of the Bonds, including the 2024 Series A Bonds, the Indenture and any Parity Swaps.

"Revenues" under the Indenture are: (a) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to the Project as they relate to the Power Sales Agreement or to the payment of the costs of the Project received or to be received by the Authority or the Trustee under the Power Sales Agreement or under any other contract for the sale by the Authority of capacity and energy of the Project or any contractual or other arrangement with respect to the Project relating to the Power Sales Agreement or any portion thereof or the capacity or energy thereof; (b) proceeds received by or for the account of the Authority of any insurance or of contractors' performance or guarantee bonds or other assurances of completion or levels of performance with respect thereto in connection with the Project or any Capital Improvement; and (c) any condemnation awards received by or for the account of the Authority in connection with the Project; but excluding (x) interest and other investment income received or to be received on any moneys or securities held pursuant to an indenture of trust entered into by the Authority with respect to bonds, notes or other evidences of indebtedness payable on a basis subordinate to the 2024 Series A Bonds and any other Bonds except to the extent that the Authority specifies that such interest and other investment income shall constitute Revenues, (y) amounts received by or on behalf of the Authority pursuant to any interest rate swap agreement or interest rate cap agreement relating to the Indenture except to the extent that the Authority specifies that such amounts shall constitute Revenues and (z) amounts received by or on behalf of the Authority pursuant to a Letter of Credit relating to the Indenture except to the extent that the Authority specifies that such amounts shall constitute Revenues.

The 2024 Series A Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), the Project Participant or any other member of the Authority, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2024 Series A Bonds. The 2024 Series A Bonds shall never constitute the debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution or statutes of the State of California and shall not constitute nor give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power.

See "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Indenture" in Appendix B hereto for certain definitions and further discussion of certain of the terms and provisions of the Indenture.

Authority Rate Covenant

Pursuant to the Indenture, the Authority has covenanted to at all times establish and collect (or cause to be collected) amounts for the sale of Facility Output, or in respect of or for the use of the Project, as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of the following:

(i) Authority Operating Expenses during such Fiscal Year;

(ii) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(iii) The amount, if any, to be paid during such Fiscal Year into the Participating Bonds Debt Service Reserve Account and any Series Debt Service Reserve Account;

(iv) The amount, if any, to be paid during such Fiscal Year into the Reserve and Contingency Fund;

(v) The amount, if any, to be paid during such Fiscal Year into the Decommissioning Fund;

(vi) The amount, if any, required to be paid into any fund or account during such Fiscal Year with respect to bonds, notes or other evidences of indebtedness payable on a basis subordinate to the Bonds;

(vii) The amount, if any, required to be deposited in the General Reserve Fund during such Fiscal Year; and

(viii) The amount, if any, required to pay all other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

Flow of Funds

The Indenture establishes the following Funds and Accounts, each of which is held by the Trustee under the Indenture: (i) Project Fund; (ii) Revenue Fund; (iii) Operating Fund (consisting of the Operating Account and the Operating Reserve Account); (iv) Debt Service Fund; (v) Debt Service Reserve Fund; (vi) Reserve and Contingency Fund; (vii) Decommissioning Fund; and (viii) General Reserve Fund. The Project Fund includes the following accounts therein: the Apex Power Project, Refunding Revenue Bonds and the Apex Power Project, Refunding Revenue Bonds, 2024 Series A, Costs of Issuance Account therein as established under the Third Supplemental Indenture. The Debt Service Fund includes the following accounts therein: (A) the Participating Bonds Debt Service Account; (B) each Series Debt Service Account established pursuant to a future Supplemental Indenture providing for the issuance of a Series of Bonds that are not Participating Bonds (the Participating Bonds Debt Service Account and each Series Debt Service Account being referred to herein as a "Debt Service Account"); and (C) each Letter of Credit Account, if any, established pursuant to a future Supplemental Indenture providing for the issuance of a Series of Bonds for which a Letter of Credit is provided. The Debt Service Reserve Fund includes the following accounts therein: (A) the Participating Bonds Debt Service Reserve Account; and (B) each Series Debt Service Reserve Account (if any) established pursuant to a future Supplemental Indenture providing for the issuance of a Series of Bonds that are not Participating Bonds (the Participating Bonds Debt Service Reserve Account and each Series Debt Service Reserve Account being referred to herein as a "Debt Service Reserve Account").

Pursuant to the Indenture, all Revenues (except as otherwise provided in the Indenture with respect to proceeds of any condemnation awards or proceeds of insurance or of contractors' performance or guarantee bonds or other assurances of completion or levels of performance), and, except as otherwise provided in a Supplemental Indenture, any interest and other investment income received on any moneys or securities held pursuant to the Indenture, received by the Trustee are to be deposited promptly in the Revenue Fund. Amounts in the Revenue Fund are to be paid monthly to the following Funds and Accounts in the following order of priority:

(1) To the (i) Operating Account, a sum that is equal to the total moneys appropriated for Authority Operating Expenses for deposit in the Operating Account as provided in the Annual Budget (as defined below) for the then current month and (ii) Operating Reserve Account, the amount required so that the amount in the Operating Reserve Account will equal the amount required to be in such Account as provided in the Annual Budget. There may be deposited in the Operating Reserve Account proceeds of Bonds or any portion thereof or moneys received in connection with the Project or any portion thereof from any other source, as provided in the Indenture, unless required to be applied as otherwise provided in the Indenture. Any excess amounts in the Operating Account or the Operating Reserve Account, as determined by the Authority, will be applied to make up any deficiencies in the other Funds or Accounts established pursuant to the Indenture as described therein; and thereafter any remaining excess shall be transferred to the General Reserve Fund.

(2) To the Debt Service Fund (for the ratable security and payment pursuant to clause (i) and clause (ii) of this paragraph (2) (except as otherwise provided in the Indenture and subject to the provisions thereof)), (i) (A) for credit to the Participating Bonds Debt Service Account the amount, if any, required so that the balance in said Account shall equal the Accrued Debt Service with respect to the Participating Bonds as of the last day of the then current month, and (B) for credit to each Series Debt Service Account, the amount, if any, required so that the balance in each such Account shall equal the Accrued Debt Service with respect to the related Series of Bonds as of the last day of the then current month (excluding the amount, if any, set aside in such Account from the proceeds of Bonds (including amounts, if any, transferred from the Project Fund) for the payment of interest on the related Bonds, less that amount of such proceeds to be applied in accordance with the Indenture to the payment of interest accrued and unpaid and to accrue on such related Bonds to the last day of the then current calendar month) and (ii) (A) for credit to the Participating Bonds Debt Service Account, the amounts due and payable by the Authority during such month under any Parity Swap which shall be designated to the Trustee by an Authorized Authority Representative as a Parity Swap for Participating Bonds as provided in the related Supplemental Indenture or Supplemental Indentures, and (B) for credit to each Series Debt Service Account, the amounts due and payable by the Authority during such month under any Parity Swap which shall be designated to the Trustee by an Authorized Authority Representative as a Parity Swap for the related Series of Bonds as provided in the related Supplemental Indenture or Supplemental Indentures (with any termination payments under any Parity Swaps to be payable on a basis subordinate and junior to the payments to be made on the Bonds); provided, however, that, in any event, if there is a deficiency of Revenues to make all of the deposits required, such Revenues shall be deposited into each Debt Service Account on a pro rata basis based on the amounts due. The Trustee will apply amounts in the Participating Bonds Debt Service Account to the payment of principal of and interest on the Participating Bonds [(including the 2024 Series A Bonds)], and will apply amounts in each Series Debt Service Account to the payment of principal of and interest on the related Series of Bonds.

(3) To the Debt Service Reserve Fund, for credit to the Participating Bonds Debt Service Reserve Account and each Series Debt Service Reserve Account, the amount, if any, required to be deposited therein so that the balance in each such Account shall be equal to the requirement therefor as of the last day of the then current month; provided, however, that, in any event, if there shall be a deficiency of Revenues to make all of the deposits required, such Revenues shall be deposited into each Debt Service Reserve Account on a pro rata basis based on the amounts due.

(4) To the Reserve and Contingency Fund, the amount, if any, provided for deposit therein during the then current month as provided in the Annual Budget, in accordance with written instructions from the Authority.

(5) To the Decommissioning Fund, the amount, if any, budgeted for deposit therein for the then current month as provided in the Annual Budget, in accordance with written instructions from the Authority.

(6) To the General Reserve Fund, the balance, if any, in the Revenue Fund after making the above deposits.

For a more detailed discussion of the application of moneys deposited in the various funds and accounts, see "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Indenture – Application of Revenues" in Appendix B hereto.

Participating Bonds Debt Service Reserve Account

Pursuant to the Indenture, all Bonds other than any Series of Bonds issued pursuant to a Supplemental Indenture that provides that such Series of Bonds are not Participating Bonds shall be "Participating Bonds" and shall be secured by the Participating Bonds Debt Service Reserve Account. [The 2024 Series A Bonds constitute Participating Bonds.] [To be revised if no reserve will be funded.] The Indenture provides that there is required to be maintained in the Participating Bonds Debt Service Reserve Account, as of any date of calculation, an amount equal to twenty-five percent (25%) of the greatest aggregate annual Debt Service coming due in the current or any future Fiscal Year with respect to the Outstanding Participating Bonds (the "Debt Service Reserve Requirement"), which amount, upon the issuance of the 2024 Series A Bonds is $[____].

If on the last Business Day of any month the amount in the Participating Bonds Debt Service Account shall be less than the amount required to be in such Account with respect to the Participating Bonds (including the 2024 Series A Bonds), the Trustee will pay out of the Participating Bonds Debt Service Reserve Account (to the extent available) for credit to the Participating Bonds Debt Service Account the amount necessary to restore the balance therein to the required amount.

In the event that the balance in the Participating Bonds Debt Service Reserve Account shall at any time be less than the Debt Service Reserve Requirement applicable to such Account, the deficiency in such Account shall be replenished by the deposit monthly into such Account pursuant to the provisions of the Indenture of at least one-twelfth (1/12) of the aggregate amount of each unreplenished prior withdrawal from such Account and the full amount of any portion of any such deficiency due to the required valuations of the investments in such Account until the balance in such Account is at least equal to the Debt Service Reserve Requirement applicable to such Account.

At the option of the Authority amounts required to be held in the Participating Bonds Debt Service Reserve Account may be substituted, in whole or in part, by the deposit with the Trustee of a surety bond, insurance policy, line of credit, letter of credit or similar instrument issued to the Trustee by an entity licensed to issue a surety bond, insurance policy, line of credit, letter of credit or similar instrument guaranteeing the timely payment of debt service on the Participating Bonds (a "municipal bond insurer"), which municipal bond insurer, at the time any such surety bond, insurance policy, line of credit, letter of credit or similar instrument is issued, shall have its claims paying ability rated in not lower than the second highest rating category (without regard to any gradations within any such category) by at least two nationally-recognized credit rating agencies (a "Debt Service Reserve Account Policy") in a stated amount equal to the amounts so substituted. Any such Debt Service Reserve Account Policy then held in the Participating Bonds Debt Service Reserve Account may be replaced at the option of the Authority by cash or another Debt Service Reserve Account Policy in whole or in part. Prior to the substitution or replacement of such Debt Service Reserve Account Policy the Rating Agencies then rating the Participating Bonds (including the 2024 Series A Bonds) are required to have been notified by the Authority of such proposed substitution or replacement, and the substitution or replacement shall not result, as evidenced by letters from such Rating Agencies, in a downgrading or withdrawal of any rating of the Participating Bonds (including the 2024 Series A Bonds) then in effect by such Rating Agencies, and the Authority shall have first received an Opinion of Bond Counsel to the effect that such substitution or replacement will not adversely affect the exclusion of interest on the Participating Bonds from the gross income of the Owners thereof for federal income tax purposes, if applicable.

So long as any Debt Service Reserve Account Policy shall be in full force and effect for Participating Bonds, there shall also be paid out of the Participating Bonds Debt Service Reserve Account any amounts necessary to reimburse the provider of any such Debt Service Reserve Account Policy credited to such Account for any draw on such Debt Service Reserve Account Policy, together with interest or any other amounts due to such provider of a Debt Service Reserve Account Policy as a result of such draw, pursuant to the terms of the Debt Service Reserve Account Policy or any related agreement with the provider thereof.

As described above, the Indenture provides that a Supplemental Indenture authorizing a Series of Bonds may provide that such Bonds are not Participating Bonds (all such Bonds being referred to as "Non-Participating Bonds") and may be secured by a Series Debt Service Reserve Account. Amounts on deposit in any Series Debt Service Reserve Account for any Non-Participating Bonds shall be used and withdrawn as provided in the Indenture or in the applicable Supplemental Indenture authorizing the issuance of such Non-Participating Bonds. Amounts on deposit in the Participating Bonds Debt Service Reserve Account secure only Participating Bonds (including the 2024 Series A Bonds) and do not secure in any manner any Series of Non-Participating Bonds. Amounts on deposit in any Series Debt Service Reserve Account do not secure in any manner the 2024 Series A Bonds or any other Participating Bonds.

Additional Bonds

Upon issuance of the 2024 Series A Bonds, there will be no other Bonds outstanding payable from Revenues on a parity with the 2024 Series A Bonds. The Authority reserves the right to issue additional Bonds under the Indenture for the purposes of the Project (including to pay, if necessary, the costs of any Capital Improvements with respect to the Project) on, and subject to, the terms and conditions set forth in the Indenture. Refunding Bonds may also be issued subject to certain terms and conditions. Such Bonds would rank equally as to security and payment with the 2024 Series A Bonds and any other Bonds issued under the Indenture. See "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Indenture – Certain Requirements of and Conditions to Issuance of Bonds" and "– Refunding Bonds" in Appendix B hereto.

Power Sales Agreement

General. In accordance with the Indenture, payments made by the Department under the Power Sales Agreement constitute Revenues securing the payment of debt service on the Bonds (including the 2024 Series A Bonds).

Term of the Power Sales Agreement. The Power Sales Agreement constitutes an obligation of the Authority and the Department until the expiration of its term on the later of (i) the date the Joint Powers Agreement, including any extension thereof, expires, or (ii) the date on which all Bonds issued by the Authority to finance or refinance the cost of acquisition of the Project and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made and such Bonds are no longer outstanding. However, the Power Sales Agreement may be terminated earlier if all such Bonds and all interest thereon shall have been paid in full or adequate provision for such payment shall have been made and such Bonds are no longer outstanding and either (i) the Power Sales Agreement is superseded as a result of the Department having (a) become the owner of the Project under some form of ownership agreement, (b) entered into a replacement power sales agreement or other agreement with the Authority or (c) entered into a replacement power sales agreement or other agreement after having become an owner of the Project under some form of ownership agreement. As long as any of the Bonds are outstanding, the Power Sales Agreement may not be terminated, amended, modified or otherwise altered in any manner that will materially reduce the payments pledged as security for the Bonds or extend the time of such payments provided in the Power Sales Agreement or that will materially adversely impair or materially adversely affect the rights of the owners of the Bonds.

Annual Budget. The Power Sales Agreement requires the Authority to prepare and submit to the Department a proposed annual budget (the "Annual Budget") at least 60 days prior to the beginning of each Power Supply Year (*i.e.*, each Fiscal Year, except that the first annual budget shall be prepared, considered, adopted and delivered in the most practical manner available). The Authority will incorporate into the Annual Budget the operating budget (including a fuel budget and provisions for payment of costs of Capital Improvements which are not being financed by proceeds of Bonds) for such Power Supply Year as prepared with the collaboration of the Department and the Authority for approval by the Authority's Board of Directors. The Department may then submit to the Authority, at any time until the Annual Budget is adopted, any matters or suggestions relating to the Annual Budget. The Authority is required to adopt the Annual Budget not less than 30 nor more than 45 days prior to the beginning of such Power Supply Year and shall cause copies of such adopted Annual Budget to be delivered to the Department; provided, however, that the Annual Budget for the first Power Supply Year shall be prepared, considered, adopted and delivered in the most practicable manner available.

Covenant to Maintain Sufficient Rates. The Department has covenanted in the Power Sales Agreement to establish, maintain and collect rates and charges for its electric service of its electric system sufficient to provide revenues which, together with any legally available electric power system reserves, are sufficient to enable it to pay to the Authority when due all amounts payable under the Power Sales Agreement and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

Unconditional Obligation. Power costs of the Project are the costs to the extent not included in the cost of acquisition of the Project or paid from the proceeds of bonds, notes or other evidence of indebtedness issued in anticipation of bonds, resulting from the ownership, management, administration, operation and maintenance of and renewals and replacements to the Project (the "Power Costs"). Power Costs payments under the Power Sales Agreement are to be made by the Department on a "take-or-pay" basis, that is, whether or not the Project or any part thereof, is functioning, producing, operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance by any party of any agreement for any cause whatever.

Monthly Power Costs. The amount of the Project's monthly Power Costs ("Monthly Power Costs") to be paid by the Department under the Power Sales Agreement for a particular Month shall be the sum of the following:

(1) an amount that is 1/12 of the Project's *operating cost component,* which amount shall be payable for such Month;

(2) the amount of the Project's *fuel cost component* for natural gas procured or acquired by or on behalf of the Authority for use in the Facility (the "Project Fuel"), which amount shall be payable for such Month;

(3) the Project's *Indenture cost component,* which shall be payable for such Month; and

(4) the Project's s*upplementary services cost component,* which shall be payable for such Month.

By the fifth calendar day of each Month during each Power Supply Year, the Authority will bill the Department for the amount of Monthly Power Costs to be paid by the Department for the current Month by providing the Department with a Billing Statement pursuant to the provisions of the Power Sales Agreement. The Billing Statement will detail the costs described above and will set forth, among other things, the amounts due for such Month by the Department with respect to the items of Monthly Power Costs set forth in the Power Sales Agreement, as such Monthly Power Costs may be adjusted from time to time in accordance therewith. Such Billing Statement shall be paid by the Department on or before 20 days after receipt of such Billing Statement.

The *operating cost component* of the Power Costs will consist of: the costs of all Operating Work, operating expenses and all costs of producing and delivering the Facility Output of the Project during such Power Supply Year, including, but not limited to: (i) ordinary operation and maintenance costs, costs of repairs, replacements and reconstruction of the Project that do not entail Capital Improvements, administrative and general costs, costs relating to litigation (including attorneys' fees and disbursements and other amounts paid as a result of such litigation), insurance costs (including amounts paid to fund any self-insurance program), overhead costs, taxes required to be paid by the Authority with respect to the Project, and any other costs payable by the Authority in connection with the output of the Project; (ii) all costs of compliance by the Authority with its indemnification obligations under the Power Sales Agreement; (iii) all costs related to the conducting of the business of the Authority with respect to the Project, including the applicable portion of salaries, fees for legal, engineering, financial and other services, all costs attributable to miscellaneous and incidental expenses in connection with the administration of the Project, all costs and expenses with respect to payment and performance of the Authority's obligations under the Agency Agreement (including any and all payments, costs and expenses with respect to compliance with its indemnification obligations under the Agency Agreement or costs and expenses under any other agreement with the Project Manager); (iv) all Agency Costs (as defined in the Agency Agreement); and (v) all other expenses properly related to the conduct of such affairs of the Authority; provided further, however, that operating costs shall, with respect to Project Fuel costs, include only the fixed costs of Project Fuel, including but not limited to the following:

(1) The cost of Project Fuel associated with the load upon the Facility when the generation station's gross output equals the Capacity and Energy required to operate the Facility's generating unit auxiliaries and other equipment and systems used or required at the Facility in connection with the operation and maintenance of the Facility;

(2) The cost of Project Fuel storage at the plant site, if any; and

(3) The cost associated with contract payments under minimum or guaranteed payment provisions for Project Fuel or Project Fuel transmission or transportation which are determined by the Project Manager and/or the Authority's Board of Directors to constitute fixed costs of Project Fuel;

provided that, in the event that the Department elects to procure its own fuel in accordance with the Power Sales Agreement, the operating cost component of Power Costs for the period during which the Department procures its own fuel shall include fuel costs as provided in paragraphs (1)-(3) immediately above only if and to the extent such costs shall be applicable to Project Fuel.

The *fuel cost component* of the Power Costs for any Month of such Power Supply Year will consist of the cost of Project Fuel and Project Fuel transmission and transportation budgeted for such Month as set forth in the fuel cost budget included in the Annual Budget and not otherwise included in the operating cost component described above; provided that, for the avoidance of doubt, if and to the extent that the Department elects to procure its own fuel in accordance with the Power Sales Agreement, such fuel cost component shall not be applicable for the period during which the Department procures its own fuel for the Project, except with respect to costs of Project Fuel, if any.

The *Indenture cost component* of the Power Costs for any Month of such Power Supply Year will consist of:

(1) The amount which the Authority is required under any indentures of trust, including the Indenture, to pay or deposit during such Month into any funds or accounts established by such indentures of trust for Debt Service and for any reserve requirements for the Bonds (including the 2024 Series A Bonds) or reserve requirements recommended by the Project Manager and approved by the Authority's Board of Directors, including replenishment (the timing of which shall be in accordance with the provisions of the Power Sales Agreement and the indentures of trust) of any reserves drawn down as a result of any failure of the Department to pay all or any portion of the Monthly Power Costs; provided, however, that such amounts shall not include amounts included in a Default Invoice (described below) for which the Authority has received payment, or other payments received by the Authority in accordance with the Power Sales Agreement and used to replenish such reserves;

(2) The amount which the Authority is required to pay or deposit during such Month into any fund or account established by any indentures of trust, including the Indenture, for the payment of interest on notes or other evidences of indebtedness issued in anticipation of the issuance of Bonds; and

(3) 1/12 of the amount (not otherwise included in the Indenture cost component, the operating cost component or the fuel cost component) which the Authority is required under any indentures of trust, including the Indenture, to pay or deposit during such Power Supply Year into any other fund or account established by such indentures of trust, including the Indenture, and shall include any amounts required to make up a deficiency in any fund or account required or permitted by such indentures of trust whether or not resulting from a default in payments by the Department of amounts due under the Power Sales Agreement; provided, however, such amounts shall not include amounts included in a Default Invoice for which the Authority has received payment, or other payments received by the Authority in accordance with the Power Sales Agreement and used to replenish such fund or account.

The *supplementary services cost component* of the Power Costs for any Month of such Power Supply Year will consist of all costs of the Authority for such Month to the extent not included in the Indenture cost component, in connection with services for transmission, dispatching, scheduling, tagging, firming, balancing, swapping, exchanging or delivery of, and for otherwise facilitating the disposition, movement, taking, receiving, crediting and accounting for, the Facility Output provided for under the Power Sales Agreement.

Project Reports. The Authority is to prepare and issue to the Department the following reports each quarter of a Power Supply Year:

(1) A financial and operating statement relating to the Project; and

(2) A variance report comparing the costs in the Annual Budget versus actual costs, and the status of other cost-related issues with respect to the Project.

Amendment of Budget. As required from time to time during any Power Supply Year, after seven days' notice to the Department, the Authority may adopt an amended Annual Budget for and applicable to the remainder of such Power Supply Year.

Reconciliation of Monthly Power Costs. As soon as practicable after the end of such Power Supply Year, the Authority shall submit to the Department a detailed statement of the actual aggregate Monthly Power Costs and any other amounts payable under the Power Sales Agreement, including credits thereto, for such year and any adjustments to the aggregate Monthly Power Costs and such other amounts payable for any prior year, based on the annual audit of accounts required by the Power Sales Agreement. If for any Power Supply Year the actual amounts payable under the Power Sales Agreement exceed the amount which the Department has been billed, the Department shall pay the Authority, within 20 days of receipt of the Authority's invoice, the amount to which the Authority is entitled; if such amounts are less than the amounts billed, the Authority, unless otherwise directed by the Department, shall credit such excess against the Department's next monthly Billing Statement. Except as otherwise recommended by the Project Manager and determined by the Authority's Board of Directors, as soon as practicable after the end of each three-month period of a Power Supply Year, the Authority shall compare the actual Project Fuel costs payable during such period with the amount billed for the fuel cost component of the Monthly Power Costs during such period. The Authority will increase or decrease, as necessary, the fuel cost component of the Department's Billing Statement for the next month to reflect the difference between the amount billed for the fuel cost component and the amount paid or payable for the fuel cost component for the previous three-month period.

Participant's Failure to Pay Billing Statement. In the event the Department fails to pay all or a portion of its Billing Statement by the due date (a "Payment Default"), and fails to cure by, at any time, the earlier of five days thereafter or the last day of the then current month (the "Initial Payment Default Date"), the Authority will provide written notice to the Department that as a result of its Payment Default its Project Rights are subject to discontinuance, termination and disposal pursuant to the Power Sales Agreement. During the period from the Initial Payment Default Date and ending approximately two months later (the "Payment Default Period"), the Department's Project Rights may not be discontinued, terminated or disposed of regardless of whether or not the Department pays any of its Billing Statements due during the Payment Default Period. During such Payment Default Period, the Authority shall include with the Department's Billing Statement a separate monthly invoice that identifies the total defaulted amount owed, including late payment interest to achieve Cured Payment Default (a "Default Invoice"). If at any time during the Payment Default Period, the Department pays in full its Billing Statement and Default Invoice, the Department shall no longer be deemed in default and its Project Rights will not be discontinued, terminated or disposed of due to such Payment Default(s), and the Participant shall no longer be deemed in default under the Power Sales Agreement.

In the event that the Department's Payment Default continues beyond the Payment Default Period, for a period following the end of the Payment Default Period and ending approximately three months later (the "Cure Period"), the Department will continue to retain the Project Rights provided it so long as during the Cure Period the Department shall remain in Compliance as hereinafter described. During the Cure Period, the Department shall be in Compliance with its payment obligations under the Power Sales Agreement if it no later than the first day of the Cure Period (or such later date that a Default Invoice is received by the Department): (i) pays each of its monthly Billing Statements issued during the Cure Period when due; and (ii) pays, with each monthly Default Invoice payment during the Cure Period, at least one-third of any deficiency (determined on an aggregate basis for the three Default Invoices due during the Cure Period) it caused to the operating reserve account and the debt service reserve account under the applicable indenture of trust, as a result of its Payment Default, including any late payment interest assessed by the Authority (collectively, "Compliance"). During the Cure Period, the Authority shall include with each of the Department's Billing Statements a Default Invoice. During the Cure Period, each Default Invoice shall include the amount that must be paid to achieve Compliance. If at any time during the Cure Period the Department is in Compliance and in addition pays in full the aggregate remaining amount due as set forth in the Default Invoice (a "Cured Payment Default"), the Department's rights in the Project will not be discontinued, terminated or disposed of due to such Payment Default(s), and the Cure Period shall expire.

If at any time during the Cure Period, the Department fails to be in Compliance, the Department's Project Rights shall be immediately and permanently discontinued and terminated, and its Project Rights and Obligations shall be disposed of by the Authority in accordance with the Power Sales Agreement and procedures adopted by the Authority, provided, however, that such discontinuance and termination shall not occur if the Department, within 10 business days of failing to be in Compliance, provides to the Authority a Suspension Request Notice. Upon receipt by the Authority of the Suspension Request Notice, a Suspension Period will commence and the Department's right to receive Facility Output shall be suspended for a period beginning on the date that the Authority received the Suspension Request Notice and ending on the earlier of (a) the date on which the Department is in Compliance during the Suspension Period or (b) two years from the Initial Payment Default Date (such period, the "Suspension Period"). During a Suspension Period, the Department shall be in Compliance with its payment obligations under the Power Sales Agreement if (i) it has paid each monthly Billing Statement and each Default Invoice, including any late payment interest assessed by the Authority and (ii) no Short-Term Sales Agreement (as defined in the Power Sales Agreement) is in effect (other than any Short-Term Sales Agreement with the Department, the payment of which is current). During the Suspension Period, the Authority will suspend the right of the Department to receive the Facility Output and will use its best efforts, to the extent reasonably possible and economically beneficial, to offer the Facility Output or any portion thereof to all Authority members (including, in the Authority's sole and absolute discretion, the Department if it demonstrates, among other things, its ability to pay on a timely basis the purchase price of any Facility Output it seeks to purchase) and third parties, for sales pursuant to Short-Term Sales Agreements (not extending beyond the date that is two years from the applicable Initial Payment Default Date) on the best terms readily available pursuant to terms and conditions established by the Authority and subject to the terms of the Power Sales Agreement; provided, however, that unless the Authority determines otherwise, the Authority will not offer or permit the sale of the Facility Output or any portion thereof in such a manner or in such an amount that would, in the opinion of bond counsel to the Authority, result in or cause non-compliance with the Federal Tax Law Requirements, if any, relating to the outstanding Bonds. During the Suspension Period, the Authority shall include with each of the Department's Billing Statements a Default Invoice, which shall include the total defaulted amount owed, including late payment interest. If at any time during the Suspension Period, the Department has paid each monthly Billing Statement and each Default Invoice, including late payment interest assessed by the Authority and no Short-Term Sales Agreement is then in effect (other than any Short-Term Sales Agreement with the Department, the payment of which is current), then the Department will no longer be in default and its right to receive the Facility Output will immediately resume.

Termination and Disposal of Project Rights. If (i) at any time during the Cure Period the Department fails to be in Compliance and if it shall not have provided to the Authority a Suspension Request Notice within 10 business days of failing to be in Compliance as described above, or (ii) the Department fails to be in Compliance at the end of the Suspension Period (described above), the Department's Project Rights shall immediately and permanently be discontinued and terminated. Upon discontinuance and termination of the Department's Rights and Obligations with respect to the Project, the Department's Rights and Obligations with respect to the Project will be disposed of by the Authority in accordance with the Power Sales Agreement and procedures established by the Authority. The Power Sales Agreement requires that the Authority first offer to convey, transfer and assign the Department's Project Rights and Obligations to any requesting members of the Authority, on a temporary or permanent basis, (i) the amount requested if the aggregate of such requests does not exceed the amount of Project Rights and Obligations of the Department or (ii) a pro-rata amount (based upon the amount requested) if the aggregate of such requests exceeds the amount of Project Rights and Obligations of the Department. Each such requesting Authority member shall assume all, but not less than all, of the Department's Rights and Obligations in the Project so conveyed to it by the Authority and shall simultaneously enter into a power sales agreement with the Authority in substantially the same form as the Power Sales Agreement.

If all of the Department's Project Rights and Obligations are not so assigned, transferred or conveyed to a requesting member of the Authority, the Authority shall offer to convey, transfer and assign, on a temporary or permanent basis as determined by the Authority, the remaining (or all, if applicable) Project Rights and Obligations of the Department to third parties, all in accordance with the terms, conditions and procedures established by the Authority, subject to the terms of the Power Sales Agreement and in such a manner that would, in the opinion of bond counsel to the Authority, not result in or cause non-compliance with the Federal Tax Law Requirements, if any, relating to the outstanding Bonds. Each such requesting third party shall assume all, but not less than all, of the Project Rights and Obligations so conveyed to it by the Authority.

Following termination and conveyance of the Department's Project Rights and Obligations as described above, the Department's obligation to make payments under its Power Sales Agreement will not be eliminated or reduced except to the extent of moneys received by the Authority as a result of the conveyance, transfer or assignment of its Project Rights and Obligations, less the Authority's related costs and expenses. However, the Department's payment obligations may be eliminated or reduced if no Bonds (including the 2024 Series A Bonds) are outstanding under any indentures of trust (including the Indenture) or adequate provision for the payment thereof has been made in accordance with the provisions of the applicable indenture of trust and the Authority's Board of Directors, by resolution, determines to eliminate or reduce such payment obligations, which determination may not be unreasonably withheld.

If the Authority is not able to convey, transfer and assign all of the Project Rights and Obligations of the Department as described above, the Authority will use its best efforts, to the extent reasonably possible and economically beneficial, to offer to all Authority members and third parties, for long-term or short-term sales as determined by the Authority, Facility Output or any portion thereof associated with such Project Rights on the best terms readily available in accordance with the terms and conditions established by the Authority and subject to the terms of the Power Sales Agreement, provided that the Authority will not offer or permit the sale of any Facility Output in a manner or amount that would, in the opinion of bond counsel to the Authority, result in or cause non-compliance with Federal Tax Law Requirements applicable to any outstanding Bonds. In the case of the sale of Facility Output with respect to the Department's Project Rights, the obligation of the Department to make payments under the Power Sales Agreement, including payment of the costs and expenses of the Authority related to such default and sale, will not be eliminated or reduced except to the extent that payments are received by the Authority from the sale of such Facility Output.

Use of Operating Reserve Account. With respect to a Payment Default by the Department, funds (if any) in the Operating Reserve Account under the applicable indenture of trust shall be used, to the extent necessary and the extent available, to cover any deficiency in the operating account under such indenture of trust to pay for the Project's operating expenses (as described in the applicable indenture of trust). No assurance can be given that in the future moneys will be on deposit in such operating reserve accounts, including the Operating Reserve Account, under the applicable indenture of trust. The Operating Reserve Account is not being funded in connection with the issuance of the 2024 Series A Bonds.

Use of Debt Service Reserve Accounts. With respect to a Payment Default by the Department, funds (or any surety bonds or similar instruments) in the debt service reserve account(s) under the applicable indenture of trust (if any) shall be used, to the extent necessary and to the extent available, to cover any shortfall in the related debt service account(s) relating to such indenture of trust to pay for debt service.

Application of Moneys Received from Default Invoices. The Authority shall forward or cause to be forwarded to the Trustee for deposit into the revenue fund of the applicable indenture of trust, the applicable portion of moneys received with respect to the payment of Default Invoices.

Application of Moneys Received from Compliance Payments. Moneys received by or on behalf of the Authority from the Department to remain in Compliance with respect to a Payment Default shall be paid as follows:

(i) With respect to the Department's first payment to remain in Compliance, the Authority shall forward or cause to be forwarded the moneys received to the Trustee for deposit into the revenue fund of the applicable indenture of trust, as appropriate, in accordance with such indenture of trust.

(ii) With respect to the Department's payments to remain in Compliance other than the first payment, the Authority shall forward or cause to be forwarded the moneys received to the Trustee for deposit into the appropriate fund (including, if applicable, the Revenue Fund) under the applicable indenture of trust, in accordance with such indenture of trust.

Application of Moneys Received from Sales of Facility Output. Moneys received by or on behalf of the Authority from the sale of Facility Output related to the Department's Project Rights and Obligations shall be forwarded or cause to be forwarded to the Trustee applicable portions of such money for deposit into the appropriate fund. Following consultation with the Authority's Board of Directors, the Authority shall determine the disposition of any remaining moneys received from such sales of Facility Output to assure that all of the Authority's obligations to meet the requirements of indentures of trust are satisfied. The Department shall have no claim or right to any such moneys.

See "SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Power Sales Agreement" in Appendix B hereto for a further description of the Power Sales Agreement.

THE APEX POWER PROJECT

Description of the Project

The Apex Power Project (the "Project") consists of a natural gas-fired, combined cycle generating facility, nominally rated at 531 MW, located in Clark County, Nevada, and generator interconnection facilities (collectively, the "Facility"), related assets and property and interconnection and transmission contractual rights. The Facility uses combustion turbine generators and a steam turbine generator, all manufactured by General Electric. The combustion turbine generators are model 7241FA ("7F/FA") and are each three-phase, synchronous, hydrogen-cooled, 3,600 rotations per minute ("RPM") machines rated at 239 megavolt-amperes at 0.85 power factor while operating at 18 kV, 60 Hertz. The 7F/FA is a well-known technology in the natural-gas fired industry. The steam turbine generator is a three-phase, synchronous, hydrogen-cooled generator, with two stages of forced-air cooling. The Facility relies on heat recovery steam generators to control the formation of oxides of nitrogen. The heat recovery steam generators include a selective catalytic reduction system and use a carbon monoxide catalyst to control carbon monoxide emissions. The Facility is equipped with duct firing and power augmentation capabilities to help increase power output. The exhaust from the steam turbine generator is condensed in an air-cooled condenser. The Facility is fueled by natural gas. The Facility commenced full commercial operation in May 2003.

The Facility is interconnected through a 3.13-mile 500 kV radial generation tie line owned by Nevada Power Company (doing business as NV Energy) that connects the Facility to the Nevada Power Company's transmission system at its Harry Allen 500 kV Substation. The Large Generator Interconnection Agreement between Nevada Power Company and the Las Vegas Power Company, LLC (the "Seller"), dated July 1, 2001, provides for the interconnection of the Facility, and firm transmission service for the Facility output is provided through two Service Agreements for Long-Term Firm Point-to-Point Transmission Service, dated April 22, 2008 (together, the "TSAs"), with a point of delivery at the Mead 230 kV Substation. The term of these two agreements extends to July 30, 2030. The Authority expects to extend the term of or renew these agreements prior to their expiration date or to provide for alternative transmission service from the Facility to the Mead 230 kV Substation.

In the fiscal year ended June 30, 2023, the average heat rate was 7,390 Btu/kWh, and the equivalent availability factor was 87.93%. In the fiscal year ending June 30, 2023, the Project generated 2,531,181 MWh at a cost of $59,613,215 ($0.024/kWh). The cost of natural gas was not included.

The Facility is located approximately 30 miles northeast of Las Vegas, Nevada, in a rural, desert region adjacent to the Nevada Power Company's Silverhawk power generation facility. This property is located in unincorporated Clark County, Nevada, near, but outside of, the municipal boundaries of the City of North Las Vegas. The property is a part of a large industrial park known as the "Apex Industrial Park" and is subject to a recorded Declaration of Covenants, Conditions, and Restrictions for the Apex Industrial Park. The Project real properties consist of approximately 90 acres of land and various access and utilities easements acquired for the operation of the Project.

Operation of the Project

Operation and Maintenance Agreement. The Facility is operated by EthosEnergy Power Operations (West) LLC ("EthosEnergy") (formerly Wood Group Power Operations (West), Inc. ("Wood Group")) pursuant to an Operations and Maintenance Agreement, initially between the Seller and Wood Group, dated February 12, 2007, as amended, and assumed and further amended by the Authority (the "O&M Agreement") pursuant to the Asset Purchase Agreement. Under the O&M Agreement, EthosEnergy provides all operations, routine maintenance, budget control, purchasing, billing, and reporting for the operation of the Facility, other than the maintenance provided by General Electric International Inc. ("GEI") under the Long-Term Service Agreement discussed below. EthosEnergy, as part of its preventative maintenance, performs, among other things, lube oil and transformer oil analysis, vibration analysis on rotating equipment, and thermal-imaging on both the electrical equipment and the heat recovery steam generators. The O&M Agreement expires on February 12, 2028. EthosEnergy has served as the operator of the Facility since it achieved commercial operation in 2003.

Long-Term Service Agreement. Major maintenance, including parts supply, parts repair and labor for the Facility's combustion turbine generators and the steam turbine are provided pursuant to a Long-Term Service Agreement between the Authority and GEI, dated June 16, 2004, as amended (the "LTSA"). The LTSA expires with respect to each gas turbine on the later of the following: (i) the later of (a) the date on which a gas turbine accrues 112,000 actual Factored Fired Hours (as defined in the LTSA) or (b) 3,600 Factored Starts (as defined in the LTSA), and (ii) the date of completion of the fourth Hot Gas Path (as defined in the LTSA) inspection. The LTSA expires with respect to the steam turbine on the date that the LTSA has expired with respect to either of the gas turbines. It is not possible to determine when the LTSA will expire. The Department currently anticipates that the LTSA will expire in 2024. The Department, as the Project Manager, will administer, supervise, monitor and enforce the O&M Agreement and the LTSA in accordance with the Agency Agreement. See “SUMMARIES OF CERTAIN DOCUMENTS – Summary of Certain Provisions of the Agency Agreement” in Appendix B hereto.

Fuel Supply. The natural gas to fuel the Facility is provided by the Department and delivered by facilities owned by the Kern River Gas Transmission Company (“Kern River”). A 20-inch diameter underground pipeline is used to provide the natural gas to the Facility. The Authority has entered into an Operational Balancing Authority agreement and letter agreement that provides the Authority with relevant data about Kern River’s facilities, and took assignment of a facilities agreement and an operating agreement that requires Kern River to operate certain metering facilities.

Water Supply. Water for the Facility is currently provided by Las Vegas Valley Water District (“LVVWD”) pursuant to an Agreement, dated June 5, 2001, by and between LVVWD and Mirant Las Vegas, LLC (which was assigned to the Seller), as amended, and including the Consent to Assignment and Amendment No. 2 to Agreement, which became effective upon the acquisition of the Apex Power Project by the Authority (the “Water Agreement”), among LVVWD, the Seller, the Authority and, for limited purposes, Silver State Energy Association (“Silver State”). Unless extended, this Water Agreement expires on June 5, 2038. If the Water Agreement is not extended, the Authority will consider obtaining water from an alternate source.

In connection with the extension of the term of the Water Agreement to June 5, 2038, the Authority, under the Energy Sales Agreement between the Authority and Silver State (the “Energy Sales Agreement”), will provide Silver State, upon its notice, 50 MW of off-peak power from any available source (including, but not limited to, the Apex Power Project). The Energy Sales Agreement will expire 25 years after the acquisition of the Apex Power Project by the Authority.

Transmission Service. Under the TSAs, Nevada Power Company currently provides transmission services to deliver the output of the Facility to the Mead 230 kV Substation. The rates, terms and conditions for such services are regulated by the Federal Energy Regulatory Commission (“FERC”) pursuant to Nevada Power Company’s open access transmission tariff.

Permits, Licenses and Approvals

The operation of the Apex Power Project is subject to a variety of federal, state and local laws and regulations. At the time the Apex Power Project was acquired by the Authority, the Seller advised the Authority that it obtained all necessary permits and approvals to own and operate the Facility. Certain of such permits and approvals were transferred to the Authority as part of the assets purchased upon the acquisition of the Apex Power Project by the Authority pursuant to the Asset Purchase Agreement, and others were acquired directly by the Authority. All necessary authority from, among others, FERC, Federal Communications Commission, Nevada Department of Wildlife, Nevada Division of Environmental Protection, Clark County Department of Air Quality and Environmental Management, Nevada Department of Business and Industry and Clark County Fire Department to operate the Apex Power Project as it is currently constructed on properties owned and/or controlled (including by easements) by the Authority are in place.

CERTAIN FINANCIAL STATEMENTS RELATING TO THE PROJECT

The following Statement of Net Position has been prepared by the Authority based upon audited financial statements of the Authority for fiscal years ended June 30, 2023 and June 30, 2022.

Southern California Public Power Authority
Apex Power Project
Statement of Net Position
(In Thousands)

	Fiscal Year Ended June 30, 2023	2022
ASSETS		
Noncurrent assets		
Net utility plant	$235,344	$246,748
Investments – restricted	21,073	18,068
Total noncurrent assets	256,417	264,816
Current assets		
Cash and cash equivalents - restricted	9,279	12,862
Cash and cash equivalents - unrestricted	6,016	9,846
Interest receivable	27	5
Accounts receivable	-	3,227
Materials and supplies	6,487	6,050
Prepaid and other assets	9,354	664
Total current assets	31,163	32,654
DEFERRED OUTFLOWS OF RESOURCES		
Reclamation and decommissioning obligation	5,773	6,139
Total deferred outflows of resources	5,773	6,139
Total assets and deferred outflows of resources	$293,353	$303,609
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$238,132	$249,709
Reclamation and decommissioning obligation	11,832	11,491
Total noncurrent liabilities	249,964	261,200
Current liabilities		
Debt due within one year	10,830	10,490
Advances from participants due within one year	22,960	21,964
Accrued interest	5,558	5,727
Accounts payable and accruals	3,782	3,905
Total current liabilities	43,130	42,086
Total liabilities	293,094	303,286
NET POSITION		
Net investment in capital assets	(10,523)	(6,241)
Restricted	(7,300)	(9,320)
Unrestricted	18,082	15,884
Total net position	259	323
Total liabilities and net position	$293,353	$303,609

The following Statement of Revenues, Expenses and Changes in Net Position has been prepared by the Authority based upon audited financial statements of the Authority for fiscal years ended June 30, 2023 and June 30, 2022.

Southern California Public Power Authority
Apex Power Project
Statement of Revenues, Expenses and Changes in Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2023	**2022**
Operating revenues:		
Sales of electric energy	$225,874	$180,831
Total operating revenues	225,874	180,831
Operating expenses:		
Operations and maintenance	199,252	156,103
Depreciation, depletion and amortization	16,892	16,529
Decommissioning	367	367
Total operating expenses	216,511	172,999
Operating income	9,363	7,832
Non-operating revenues (expenses)		
Investment and other income	1,281	57
Inflation of decommissioning liability	(341)	(955)
Other interest and debt expense	(10,367)	(10,709)
Net non-operating revenues (expenses)	(9,427)	(11,607)
Change in net position	(64)	(3,775)
Net position – beginning of year	323	4,098
Net position – end of year	$259	$323

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement expires in 2030 or on such later date as all bonds and notes of the Authority and interest thereon have been paid in full or adequate provision for such payment has been made in accordance with the instruments governing such bonds and notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement expires in 2030 or on such later date as all bonds and notes of the Authority and interest thereon have been paid in full or adequate provision for such payment has been made in accordance with the instruments governing such bonds and notes.

Organization and Management

The Authority is governed by a Board of Directors which consists of one representative for each of the members. The current representatives are listed on the masthead page of this Official Statement. The management of the Authority is under the direction of its Interim Executive Director, Randolph R. Krager, who serves at the pleasure of the Board of Directors. Mr. Krager also serves as the Treasurer/Auditor and Senior Project Development Manager of the Authority. Prior to his appointment as Interim Executive Director of the Authority in April 2024 and appointment to Senior Project Development Manager of the Authority in 2017, Mr. Krager previously served as Senior Solar and Renewable Resource Planning and Development Manager with LADWP. Mr. Krager is a 33-year veteran of LADWP and assumed various positions such as Market Analysis Manager, Resource Planning Manager, Wholesale Marketing Trading Floor Manager, Generation Project Manager, Power Systems Emergency Operations Responder, and Technical Engineer. While employed at LADWP. Mr. Krager led teams that helped with the development and procurement of LADWP's renewable portfolio, 20-year integrated resource plan and conventional generation and transmission development. He was part of the core team that established LADWP's wholesale marketing group that successfully navigated the State of California energy crisis. Mr. Krager holds a bachelor's degree in electrical engineering from the University of California at San Diego, a master's degree in electrical engineering from San Diego State University, and a master's degree in business administration from Pepperdine University.

The other officers of the Authority are selected by the Board of Directors. The President of the Authority, since January 22, 2024, is Tikan Singh, General Manager of Azusa Light and Water. Mr. Singh is a professional engineer registered in the State of California with 14 years of utilities experience. Before joining Azusa Light and Water, he worked in various capacities at Palo Alto Utilities, Lompoc Electric Utility, and the California Department of Water Resources. The First Vice President of the Authority, since February 2024, is Todd Dusenberry, General Manager of Vernon Public Utilities. He has seventeen years of public utilities experience with the City of Vernon, previously serving as a systems coordinator, systems supervisor, utilities operations manager, utilities compliance officer, utilities compliance manager and assistant general manager. He was also a board member of the California Utilities Emergency Association. The Second Vice President of the Authority, since February 2024, is Dukku Lee, General Manager of Anaheim Public Utilities. He has served Anaheim Public Utilities since November 1999 and was appointed as its General Manager in November 2013. He previously worked for Southern California Edison and Paragon Consulting Services.

Aileen Ma joined the Authority as Chief Financial and Administrative Officer in June 2019. Ms. Ma was previously Interim Utilities Assistant General Manager/Finance & Administration for the City of Riverside Public Utilities Department. Ms. Ma's employment at Riverside began in 2006. Prior to her appointment as Interim Utilities Assistant General Manager/Finance & Administration, she served in the positions of Utilities Principal Analyst and Utilities Fiscal Manager at Riverside. She has over 25 years of experience in audit, accounting and finance administration. Ms. Ma is a Certified Public Accountant, and holds a Bachelor of Science in Business Administration with an Accounting emphasis from California State University, Los Angeles and a Master of Business Administration from University of California, Irvine.

With respect to any matter involving the acquisition and financing or refinancing of an Authority project to be decided by the Board of Directors, each Director is entitled to cast votes weighted according to the size of the entitlement to the project of each project participant in addition to the vote each Director is entitled to cast as a member of the Authority. All such matters must be decided by at least 80% of the votes cast, and no such vote may be taken unless there shall be present at the meeting Directors entitled to cast more than 50% of the votes relative to such matter. Voting by the Board of Directors may take place at meetings of the Board of Directors when a quorum is present. A majority of the Board of Directors constitutes a quorum.

Other bond-financed projects of the Authority

In addition to the Apex Power Project, the following are the projects of the Authority that have been financed by bonds issued by the Authority. The principal of and premium, if any, and interest on the 2024 Series A Bonds are secured solely by and payable solely from Revenues. None of the projects described below in this subsection is payable from such Revenues.

Southern Transmission Project. *The Southern Transmission Project is to be distinguished from the Southern Transmission System Renewal Project, which is described elsewhere in this Official Statement.* The Southern Transmission System is one component of the Intermountain Power Project ("IPP," as defined herein) of IPA. Certain members of the Authority (namely, LADWP and the California cities of Anaheim, Burbank, Glendale, Pasadena and Riverside) have entered into power sales contracts with IPA pursuant to which they purchase a share of the generation and transmission capabilities of the IPP, including capacity and energy of the Intermountain Generation Station, a two-unit coal-fired, steam-electric generating plant, located in Millard County, Utah, and operating capabilities of the Southern Transmission System. The Authority acquired from each of such members its entitlement rights to capacity of the Southern Transmission System and agreed in return to issue bonds (defined above as "Existing STS Bonds"), notes or other evidences of indebtedness and make payments-in-aid of construction to IPA therefor (the "Southern Transmission Project"). All of the facilities of the IPP have been in commercial operation since May 1, 1987. The Authority has sold all of its acquired capability of the Southern Transmission System, on a "take or pay" basis, through transmission service contracts with the Original Transmission Service Purchasers. The currently operative IPP power sales contracts pursuant to which such Original Transmission Service Purchasers have obtained their rights for the delivery of the IPP generation entitlements over the Southern Transmission System, as well as the Original Transmission Service Contracts, are scheduled to terminate on June 15, 2027. The Authority had outstanding $116,535,000 aggregate principal amount of Existing STS Bonds as of April 1, 2024.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Southern Transmission System Renewal Project.

Southern Transmission Renewal Project. *The Southern Transmission Renewal Project is to be distinguished from the Southern Transmission Project, which is described above.* The Southern Transmission Renewal Project is in progress and initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. Certain members of the Authority (namely, LADWP and the California cities of Burbank and Glendale) have entered into power sales contracts with IPA pursuant to which they purchase a share of the generation and transmission capabilities of the IPP, including capacity and energy of the Intermountain Generation Station, and operating capabilities of the Southern Transmission System as upgraded and improved by the Southern Transmission Renewal Project. Such purchased shares become effective upon termination of the currently operative IPP power sales contracts related to the Southern Transmission Project described above under " - Southern Transmission Project." The Authority acquired from each of such members its entitlement rights to capacity of the Southern Transmission System and agreed in return to issue bonds ("STS Renewal Bonds"), notes or other evidences of indebtedness and make payments-in-aid of construction to IPA therefor. The Authority has sold all of its acquired capability of the Southern Transmission System as upgraded and improved by the Southern Transmission Renewal Project, on a "take-or-pay" basis, through transmission service contracts with LADWP and the California cities of Burbank and Glendale. The IPP power sales contracts in connection with the Southern Transmission Renewal Project pursuant to which such Southern Transmission Renewal Project participants have obtained their rights for the delivery of the IPP generation entitlements over the Southern Transmission System are scheduled to terminate on June 15, 2077. The Authority had outstanding $686,190,000 aggregate principal amount of STS Renewal Bonds as of April 1, 2024.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Southern Transmission System Project.

Mead-Adelanto Project, Authority Interest (Multiple Members). The Mead-Adelanto Transmission Project consists of an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. By connecting to Marketplace Substation, the line interconnects with the Mead-Phoenix Transmission Project and with the existing McCullough Substation in southern Nevada. The transmission line has a transfer capability of 1,291 MW. The current owners of the Mead-Adelanto Transmission Project are the Authority and StarTrans IO, L.L.C. The Authority has three separate and independent ownership interests in the Mead-Adelanto Project under the related joint ownership agreement: (i) one interest for the nine Authority members participating in that portion of the project acquired in connection with the original construction of the project (i.e., the Authority Interest (Multiple Members) in such project), the acquisition and construction of which was financed with revenue bonds of the Authority; (ii) one interest for Western Area Power Administration ("Western"), the funding for which is provided by Western; and (iii) an additional interest acquired by the Authority in 2016 from M-S-R Public Power Agency, for the benefit of LADWP only (i.e., the Authority Interest (LADWP Only) in such project) hereinafter described (see "– *Mead-Adelanto Project, Authority Interest (LADWP Only)*" below), the acquisition of which was financed through a separate issue of revenue bonds of the Authority issued for the benefit of LADWP only. The Authority Interest (Multiple Members) in the Mead-Adelanto Project provides to the Authority a 67.9167% member-related ownership share in the Mead-Adelanto Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (Multiple Members) in the Mead-Adelanto Project through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID, and the California cities of Cerritos and Vernon). From and after July 1, 2020, the Authority had no bonds outstanding with respect to the Authority Interest (Multiple Members) in the Mead-Adelanto Project.

Mead-Phoenix Project, Authority Interest (Multiple Members). The Mead-Phoenix Transmission Project consists of an approximately 256-mile, 500-kV alternating current ("AC") transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. The line is looped through the 500-kV switchyard constructed in the existing Mead Substation in southern Nevada with a transfer capability of 1,923 MW (as a result of upgrades completed in 2009). By connecting to Marketplace Substation, the Mead-Phoenix Transmission Project interconnects with the Mead-Adelanto Transmission Project and with the existing McCullough Substation. The current owners of the Mead-Phoenix Transmission Project are the Authority, Arizona Public Service Company, Salt River Project and StarTrans IO, L.L.C. The Authority has three separate and independent ownership interests in the Mead-Phoenix Project under the related joint ownership agreement: (i) one interest for the nine Authority members participating in that portion of the project acquired in connection with the original construction of the project (i.e., the Authority Interest (Multiple Members) in such project), the acquisition and construction of which was financed with revenue bonds of the Authority; (ii) one interest for Western, the funding for which is provided by Western; and (iii) an additional interest acquired by the Authority in 2016 from M-S-R Public Power Agency, for the benefit of LADWP only (i.e., the Authority Interest (LADWP Only) in such project) hereinafter described (see "*– Mead-Adelanto Project, Authority Interest (LADWP Only)*" below), the acquisition of which was financed through a separate issue of revenue bonds of the Authority issued for the benefit of LADWP only. The Mead-Phoenix Transmission Project is comprised of three project components. The Authority Interest (Multiple Members) in the Mead-Phoenix Project provides to the Authority an 18.3077% member-related ownership share in the Westwing-Mead Component, a 17.7563% member-related ownership share in the Mead Substation Component, and a 22.4082% member-related ownership share in the Mead-Marketplace Component of the Mead-Phoenix Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (Multiple Members) in the Mead-Phoenix Project through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID, and the California cities of Cerritos and Vernon). From and after July 1, 2020, the Authority had no bonds outstanding with respect to the Authority Interest (Multiple Members) in the Mead-Phoenix Project.

Mead-Adelanto Project, Authority Interest (LADWP Only). In 2016, the Authority acquired, for the benefit of LADWP only, all of M-S-R Public Power Agency's ownership interest in the Mead-Adelanto Project, representing an additional 17.5000% ownership interest in the Mead-Adelanto Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (LADWP Only) in the Mead-Adelanto Project through a transmission service contract with LADWP. The Authority had outstanding $15,980,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Adelanto Project as of April 1, 2024.

Mead-Phoenix Project, Authority Interest (LADWP Only). In 2016, the Authority acquired, for the benefit of LADWP only, all of M-S-R Public Power Agency's ownership interest in the Mead-Phoenix Project, representing an additional 11.5385% ownership interest in the Westwing-Mead Component and an additional 8.0993% ownership share in the Mead-Marketplace Component of the Mead-Phoenix Project. The Authority has sold, on a "take-or-pay" basis, the entire capability of its Authority Interest (LADWP Only) in the Mead-Phoenix Project through a transmission service contract with LADWP. The Authority had outstanding $12,975,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Phoenix Project as of April 1, 2024.

Palo Verde Nuclear Generating Station. The Authority, pursuant to the Arizona Nuclear Power Project Participation Agreement, has a 5.91% ownership interest in Palo Verde Nuclear Generating Station Units 1, 2 and 3 (the "Generating Station"), including certain associated facilities and contractual rights, a 5.44% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard (the "Switchyard") and contractual rights, and a 6.55% share of the rights to use certain portions of Arizona Nuclear Power Project Valley Transmission System. The Generating Station and the Switchyard are collectively referred to herein as "PVNGS."

The Authority has sold the entire capability of the Authority's interest in PVNGS pursuant to power sales contracts with nine California cities and a California irrigation district, each of which is a member of the Authority. The California cities of Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon, as well as LADWP and IID are PVNGS project participants. From and after July 1, 2017, the Authority had no bonds outstanding with respect to PVNGS.

Commercial operation and initial deliveries from PVNGS Units 1, 2 and 3 commenced in 1986 and 1987. In addition to transmission provided by the Mead-Adelanto Project and the Mead-Phoenix Project (described above), transmission is accomplished through agreements with Salt River Project, LADWP and Southern California Edison.

San Juan Unit 3 Project. The San Juan Generating Station ("San Juan") originally consisted of a 4-unit, coal-fired electric generating station located in northwestern New Mexico, approximately 15 miles northwest of the City of Farmington, in San Juan County. The combined net generating capacity of the four units was 1,647 MW, with the net generating capacity of Unit 3 being 497 MW. The four units were put into operation between 1973 and 1982. In 1993, the Authority and five of its members negotiated a purchase agreement with Century Power Corporation, under which the Authority purchased a 41.8% interest in Unit 3 and related common facilities of San Juan, entitling the Authority to approximately 208 MW of power generated by Unit 3. In this regard, the Authority entered into power sales contracts with the California cities of Azusa, Banning, Colton and Glendale, and IID. From and after January 1, 2017, the Authority had no bonds outstanding with respect to San Juan.

As part of the overall settlement of matters regarding emissions at San Juan, Unit 3 permanently ceased operations in December 2017 and effective as of December 31, 2017, the Authority has divested its ownership interest in the San Juan project. However, the Authority retains certain liabilities for a share of the environmental (mine reclamation) and plant decommissioning costs of San Juan, Unit 3.

Magnolia Power Project. The Magnolia Power Project consists of a combined-cycle natural gas-fired electric generating plant with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Power Project is owned by the Authority and was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. The Magnolia Power Project is operated by the California city of Burbank. The Authority has entered into power sales agreements with the California cities of Anaheim, Burbank, Cerritos, Colton, Glendale and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Magnolia Power Project to such participants on a "take-or-pay" basis. The commercial operation date for the Magnolia Power Project was September 22, 2005. The Authority had outstanding $219,005,000 aggregate principal amount of revenue bonds with respect to the Magnolia Power Project as of April 1, 2024 (of which $8,855,000 relates exclusively to the City of Cerritos).

Prepaid Natural Gas Project. The Prepaid Natural Gas Project primarily consists of the acquisition by the Authority of the right to receive an aggregate amount of approximately 135 billion cubic feet of natural gas (which amount has been reduced to approximately 90 billion cubic feet as a result of a restructuring described below) from J. Aron & Company ("J. Aron") pursuant to the terms of five Prepaid Natural Gas Sales Agreements between the Authority and J. Aron, each relating to a separate participant. The gas is delivered by J. Aron to the Authority at designated delivery points on the natural gas pipelines that serve the participants in specified daily quantities each month, over the approximately 30-year term (subsequently amended to a 27-year term due to the restructuring described below) of each of the Prepaid Natural Gas Sales Agreements, in exchange for the lump sum prepayment made to J. Aron by the Authority on the date of issuance of the Authority's Gas Project Revenue Bonds (Project No. 1) in 2007. The Prepaid Natural Gas Project participants are the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between the Authority and J. Aron were restructured to provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreements. As a result of the restructuring, approximately $165,000,000 principal amount of bonds with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured to, among other things, (a) provide additional credit support for payments by three of the project participants by amending and restating the associated receivables purchase agreement and The Goldman Sachs Group, Inc. guaranty, (b) replace AIG-FP Broadgate Limited with Mitsubishi UFJ Securities International plc as the party to the Authority commodity swaps, and (c) create a custodial arrangement with respect to payments owed by J. Aron and guaranteed by The Goldman Sachs Group, Inc. or to J. Aron under corresponding J. Aron commodity swaps in order to mitigate the Authority's credit exposure to Mitsubishi UFJ Securities International plc as the counterparty. The Authority has sold 100% of its interest in the natural gas, on a "take-and-pay" basis, through gas supply agreements with the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. The Authority had outstanding $247,210,000 aggregate principal amount of revenue bonds with respect to the Prepaid Natural Gas Project as of April 1, 2024.

Natural Gas Reserves Project. The Natural Gas Reserves Project includes the Authority's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the "Wyoming Subproject") and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the "Texas Subproject," and collectively with the Wyoming Subproject, the "Natural Gas Reserves Project"). The Authority has sold the entire production capacity of its leasehold interests in the Natural Gas Reserves Project by entering into gas sales agreements with the California cities of Anaheim, Burbank and Colton (collectively, the "Natural Gas Project A Participants") and with the California cities of Glendale and Pasadena on a "take or pay" basis (other than with respect to debt service, which is payable only by the Natural Gas Project A Participants on a several basis). On February 6, 2008, the Authority issued revenue bonds in three simultaneous financings (each for the benefit of a Natural Gas Project A Participant). As of April 1, 2024, the Authority had outstanding $31,190,000 aggregate principal amount of revenue bonds with respect to the Natural Gas Reserves Project, consisting of $17,815,000, $9,660,000 and $3,715,000 aggregate principal amount of the Anaheim series, the Burbank series and the Colton series, respectively.

Canyon Power Project. The Canyon Power Project consists of a simple cycle, natural gas-fired power generating plant, comprised of four General Electric LM 6000PC Sprint combustion turbines with a combined nominally rated net base capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the California city of Anaheim. The Canyon Power Project is owned by the Authority and operated and maintained by Anaheim. The Canyon Power Project was constructed for the primary purpose of providing Anaheim with firm capacity and energy to help it meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The Authority has entered into a power sales agreement with Anaheim pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Canyon Power Project to Anaheim on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $254,540,000 aggregate principal amount of revenue bonds with respect to the Canyon Power Project.

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the "Windy Point Project"). The Windy Point Project is owned and operated by Windy Flats Partners, LLC ("Windy Flats"). Pursuant to a power purchase agreement with Windy Flats, the Authority has agreed to purchase from Windy Flats all energy from the Windy Point Project for an initial delivery term expiring in 2030 (unless earlier terminated). Energy from the Windy Point Project is delivered to the Authority through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. The Authority has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs of energy from the Windy Point Project for the initial delivery term. In March 2023, the original power purchase agreement was amended to extend the delivery term for an additional four (4) years beginning September 10, 2030 through September 9, 2034. In connection with such extension, Windy Flats completed certain equipment replacements and upgrades, which are expected to maintain the project's current capacity factor for the additional four years contemplated by the amendment, plus two more years. The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its output entitlement in the Windy Point Project to such participants on a "take-or-pay" basis. LADWP has purchased Glendale's 7.63% output entitlement share of Windy Point Project's output. As of April 1, 2024, the Authority had outstanding $161,845,000 aggregate principal amount of revenue bonds with respect to the Windy Point Project.

Tieton Hydropower Project. The Tieton Hydropower Project consists of a 13.6 MW nameplate capacity "run of the reservoir" hydroelectric generation facility, comprised of (i) a powerhouse located near Rimrock Lake in Yakima County approximately 40 miles west of the City of Yakima, Washington, and constructed at the base of the Bureau of Reclamation's Tieton Dam on the Tieton River, (ii) a 21-mile 115 kV transmission line from the power plant substation to the point of interconnection with the electrical grid, and (iii) related assets, property and contractual rights, acquired by the Authority in November 2009, pursuant to an Asset Purchase Agreement, dated as of October 19, 2009, by and between the Authority and Tieton Hydropower, L.L.C., a Washington limited liability company. The Authority has entered into power sales and acquisition contracts with the California cities of Burbank and Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Tieton Hydropower Project to such participants on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $30,800,000 principal amount of revenue bonds with respect to the Tieton Hydropower Project.

Linden Wind Energy Project. The Linden Wind Energy Project consists of the acquisition by the Authority of an approximately 50 MW nameplate capacity wind powered electric generating facility comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington, including the structures, facilities, equipment, fixtures, improvements and associated real and personal property and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom. The Linden Wind Energy Project was developed and constructed by Northwest Wind Partners, LLC ("Northwest Wind"), a Delaware limited liability company. Northwest Wind undertook the development, construction, start-up, testing and commissioning of the project, and upon the completion thereof and subject to the terms of the Asset Purchase Agreement, dated as of June 23, 2009, by and between the Authority and Northwest Wind, the Authority acquired the project from Northwest Wind. The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Linden Wind Energy Project to such participants on a "take-or-pay" basis. LADWP has purchased all of Glendale's 10.00% output entitlement share of the Linden Wind Energy Project's output. As of April 1, 2024, the Authority had outstanding $74,765,000 aggregate principal amount of revenue bonds with respect to the Linden Wind Energy Project.

Milford Wind Corridor Phase I Project. *This Project is to be distinguished from the Milford Wind Corridor Phase II Project, which is described below.* The Milford Wind Corridor Phase I Project consists of the purchase by the Authority of all energy generated by a 203.5 MW nameplate capacity wind powered electric generating facility located near Milford, Utah (the "Milford I Facility"), for a term of 20 years (unless earlier terminated), pursuant to a Power Purchase Agreement, dated as of March 16, 2007, as amended, by and between the Authority and Milford Wind Corridor Phase I, LLC, a Delaware limited liability company, as the owner of the Milford I Facility. The generating facility includes 97 wind turbines, consisting of 58 Clipper C99 wind turbine generators, each with a rated capacity of 2.5 MW, and 39 General Electric 1.5 xle wind turbine generators, each with a rated capacity of 1.5 MW. Pursuant to the Power Purchase Agreement, energy from the Milford I Facility is delivered to the Authority over an approximately 88-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford I Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On February 9, 2010, the Authority issued $237,235,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford I Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford I Facility (i.e., November 16, 2009). The Authority has entered into power sales agreements with LADWP, and the California cities of Burbank and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase I Project to such participants on a "take-or-pay" basis. As of April 1, 2024, the Authority had outstanding $75,625,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase I Project.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Milford Wind Corridor Phase II Project described below.

Milford Wind Corridor Phase II Project. *This Project is to be distinguished from the Milford Wind Corridor Phase I Project, which is described above.* The Milford Wind Corridor Phase II Project consists of the purchase by the Authority of all energy generated by a 102 MW nameplate capacity, wind powered electric generating facility comprised of 68 wind turbines located near Milford, Utah (the "Milford II Facility"), for a term of 20 years (unless earlier terminated) pursuant to a Power Purchase Agreement, dated as of March 1, 2010, by and between the Authority and Milford Wind Corridor Phase II, LLC, a Delaware limited liability company, as the owner of the Milford II Facility. Pursuant to the Power Purchase Agreement, energy from the Milford II Facility is delivered to the Authority over an approximately 90-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford II Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On August 25, 2011, the Authority issued $157,465,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford II Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford II Facility (i.e., May 2, 2011). The Authority has entered into power sales agreements with LADWP and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase II Project to such participants on a "take-or-pay" basis. LADWP has purchased all of Glendale's 4.902% output entitlement share of the Milford II Facility's output. As of April 1, 2024, the Authority had outstanding $66,385,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase II Project.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Milford Wind Corridor Phase I Project described above.

Other Projects of the Authority Not Financed with Bonds

The following are the projects of the Authority for which no bonds have been issued. The principal of and premium, if any, and interest on the 2024 Series A Bonds are secured solely by and payable solely from the Revenues and certain other moneys pledged therefor under the Indenture. None of the costs associated with the projects described below in this subsection is payable from such Revenues and such other moneys pledged to the payment of the 2024 Series A Bonds.

Projects Currently Operating

Antelope Big Sky Ranch Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on August 19, 2016. The agreement expires on December 31, 2041.

Antelope DSR I Solar Project. The Authority, on behalf of the California cities of Riverside and Vernon, entered into a power purchase agreement for 50 MW of generating capacity. The commercial operation date for the project was declared on December 20, 2015. The agreement expires on December 19, 2035.

Antelope DSR II Solar Project. The Authority, on behalf of the California city of Azusa, entered into a power purchase agreement for 5 MW of generating capacity. The commercial operation date for the project was declared on December 6, 2016. The agreement expires on December 5, 2036.

Astoria 2 Solar Project. The Authority, on behalf of the California cities of Banning, Colton and Vernon, entered into a power purchase agreement for 35 MW of generating capacity from December 9, 2016 to December 31, 2021 and 45 MW of generating capacity from January 1, 2022 until the expiration of the agreement on December 31, 2036.

Casa Diablo IV Geothermal Project. The Authority, on behalf of the California city of Colton, entered into a power purchase agreement with Ormat for 16 MW of generating capacity. The commercial operation date for the project was declared on July 14, 2022. The agreement expires on July 13, 2047.

Chiquita Canyon Landfill Gas Project. The Authority, on behalf of the California cities of Burbank and Pasadena, entered into a power purchase agreement for 10 MW of generating capacity. The commercial operation date for the project was declared on November 23, 2010. The agreement expires on November 22, 2030.

On February 22, 2024, the Authority received a Notice of Force Majeure from Ameresco Chiquita Energy, LLC ("Ameresco") claiming that they were forced to shut down the facility on January 31, 2024 due to a subsurface chemical reaction in the landfill that has decreased the amount of methane and increased the amount of water vapor in the landfill gas. Additional, Ameresco has claimed that the reported subsurface chemical reaction has introduced dimethyl sulfide ("DMS") into the landfill gas which the facility is not designed to treat or remove. In their notice, Ameresco states that their ability to resume operations depends on the ability of owner of the landfill to restore the landfill gas back to its historic quality and quantity. As of March 26, 2024, no date of return has been provided by Ameresco.

Columbia Two Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 15 MW of generating capacity. The commercial operation date for the project was declared on December 19, 2014. The agreement expires on December 18, 2034.

Copper Mountain Solar 3 Project. The Authority, on behalf of LADWP and the California city of Burbank, entered into a power purchase agreement for 250 MW of generating capacity. The commercial operation date for the project was declared on April 8, 2015. The agreement expires on April 8, 2035.

Coso Geothermal Project. The Authority, on behalf of the California cities of Banning, Pasadena, and Riverside, entered into a power purchase agreement for up to 55 MW of the total 150 MW generating capacity. The delivery commencement date for the project was on January 1, 2022. The agreement expires on December 31, 2041.

Daggett Solar Power 2 Project. The Authority, on behalf of the California cities of Cerritos and Vernon, entered into power purchase agreement for the full output from a facility with a 65 MW solar generating capacity and a 33 MW/132MWh battery energy storage system. The Project achieved its commercial operation date on December 12, 2023. The term of the agreement is 20 years.

Desert Harvest II Solar Project. The Authority, on behalf of the California cities of Anaheim, Burbank, and Vernon, entered into a power purchase agreement for 70 MW of generating capacity. The Project achieved its commercial operation date on December 17, 2020. The term of the agreement is 25 years.

Don A. Campbell I Geothermal Project. The Authority, on behalf of LADWP and the California city of Burbank, entered into a power purchase agreement for approximately 16 MW of net generating capacity. The commercial operation date for the project was declared on January 1, 2014. The agreement expires on January 1, 2034.

Don A. Campbell II Geothermal Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 16 MW of net generating capacity. The commercial operation date for the project was declared on September 17, 2015. The agreement expires on September 17, 2035.

Heber 1 Geothermal Project. The Authority, on behalf of LADWP and IID, entered into a power purchase agreement for 46 MW of generating capacity. The delivery commencement date for the project to the Authority was on February 2, 2016. The agreement expires on February 2, 2026.

Kingbird Solar B Project. The Authority, on behalf of the California cities of Azusa, Colton and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on April 30, 2016. The agreement expires on December 31, 2036, unless a one-time five-year extension is exercised.

ARP-Loyalton Biomass Project. On April 2, 2018, the Authority, on behalf of LADWP, IID and the California cities of Anaheim and Riverside, entered into a power purchase agreement (the "PPA") for approximately 12 MW of generating capacity with ARP-Loyalton Cogen LLC, seller and developer of the existing biomass power generation facility in California. The commercial operation date for the project was declared on April 20, 2018. The agreement expired on April 19, 2023.

In February 2020, the operator of the project, ARP-Loyalton Cogen LLC, and its parent company American Renewable Power LLC, filed petitions for relief under Chapter 11 of Title 11 of the United States Code (the "Bankruptcy Code"), but both cases have since been converted to Chapter 7 of the Bankruptcy Code, liquidation proceedings. On April 23, 2020, the Chapter 7 trustee entered into an agreement for the sale of the ARP-Loyalton Biomass Project to Sierra Valley Enterprises LLC, a California limited liability company, which sale included substantially all real property and personal property used in the operation of the project. The Bankruptcy Court subsequently approved the sale pursuant to an order entered on May 7, 2020.

Prior to the expiration of the PPA on April 19, 2023, counsel for the Authority worked with counsel for the Chapter 7 trustee to negotiate a mutually agreeable settlement of any claims for damages and reimbursement of the legal costs incurred by the Authority and the other PPA buyers. The parties have now completed their negotiation of the form of a proposed settlement agreement (the "ARP Loyalton Settlement Agreement"). The Authority approved the proposed form of ARP Loyalton Settlement

Agreement in January 2024 and is waiting for approvals by the other PPA buyers. Thereafter, the parties will seek approval of the ARP Loyalton Settlement Agreement from the Bankruptcy Court.

Northern Nevada Geothermal Portfolio Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for up to 185 MW of generating capacity. This project is comprised of a portfolio of generating stations to be phased in over time. The first facility began delivering energy to the Authority on December 1, 2017. The last facility of the portfolio reached its delivery commencement date on December 19, 2022. The agreement expires on December 31, 2043.

Ormesa Geothermal Complex Energy Project. The Authority, on behalf of LADWP and IID, entered into a power purchase agreement for 35 MW of net generating capacity. The delivery commencement date for the project to the Authority was on January 1, 2018. The agreement expires on December 31, 2042.

Pebble Springs Wind Power Project. The Authority, on behalf of LADWP and the California cities of Burbank and Glendale, entered into a power purchase agreement for approximately 99 MW of generating capacity. The commercial operation date for the project was declared on January 31, 2009. The agreement expires on January 31, 2027.

Puente Hills Landfill Gas-to-Energy Project. The Authority, on behalf of the California cities of Banning, Colton, Pasadena and Vernon, entered into a power purchase agreement for 46 MW of generating capacity. The delivery commencement date for the project to the Authority was on January 1, 2017. The agreement expires on December 31, 2030.

On March 11, 2024, the Authority received a Notice of Force Majeure from the Los Angeles County Sanitation Districts (“Sanitation Districts”) claiming that due to lower than expected landfill gas production, the Sanitation Districts expect to cease energy sales to the Authority and seek to terminate the power purchase agreement at the end of the day on December 31, 2026.

Red Cloud Wind Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 331 MW of generating capacity. The commercial operation date for the project was declared on December 22, 2021. The term of the agreement is 20 years.

Roseburg Biomass Project. The Authority, on behalf of LADWP, IID and the California city of Anaheim, entered into a purchase agreement for 6.8 MW (out of a total generating capacity of 13.4 MW) pursuant to SB 859. See “DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation and Regulatory Provisions—Biomass Legislation” herein. The delivery commencement date was February 16, 2021. The term of the agreement is five years.

Springbok I Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 105 MW of generating capacity. The commercial operation date for the project was declared on July 11, 2016. The agreement expires on July 10, 2041.

Springbok II Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 155 MW of generating capacity. The commercial operation date for the project was declared on September 6, 2016. The agreement expires on September 5, 2043, unless a one-time three-year extension is exercised.

Springbok III Solar Farm Project. The Authority, on behalf of LADWP, entered into a power purchase agreement for 90 MW of generating capacity. The commercial operation date for the project was declared on July 19, 2019. The agreement expires on July 18, 2046, unless a one-time three-year extension is exercised.

Star Peak Geothermal Project. The Authority, on behalf of the California city of Glendale, entered into a power purchase agreement for 12.5 MW of generating capacity. The commercial operation date for the project was declared on September 28, 2022. The agreement expires on December 31, 2045.

Summer Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date for the project was declared on July 25, 2016. The agreement expires on December 31, 2041.

Whitegrass Geothermal Project. The Authority, on behalf of the California city of Glendale, entered into a power purchase agreement, for 3.0 MW of generating capacity. The delivery commencement date for the project to the Authority was on April 1, 2020. The agreement expires on December 31, 2045.

Projects Under Development

Bonanza Solar Facility. The Authority, on behalf of the California cities of Azusa and Pasadena, entered into a power purchase agreement for a 125MW portion of the full output from a 300 MW capacity solar facility and a 65MW/260MWh portion of a 195MW/780MWh battery energy storage system. The guaranteed commercial operation date is December 31, 2028. The term of the agreement is 20 years.

Eland Solar & Storage Center, Phases 1 and 2. The Authority, on behalf of LADWP and the California city of Glendale, entered into power purchase agreements for the full output from combined facilities with 400MW solar generating capacity and a 300MW/1,200MWh battery energy storage system. The expected commercial operation date for Phase 1 is September 1, 2024 and the amended expected commercial operation date for Phase 2 is July 31, 2025. The term of the agreements is 25 years.

Geysers Geothermal Project. The Authority, on behalf of the California city of Pasadena, entered into power purchase agreement for a 25 MW portion of the full output from a 725 MW capacity geothermal facility. The guaranteed delivery commencement date is January 1, 2027. The term of the agreement is 15 years.

Sapphire Solar Facility. The Authority, on behalf of the California cities of Anaheim, Pasadena, and Vernon, entered into a power purchase agreement for the full output from a facility with a 117 MW solar generating capacity and a 59MW/236MWh battery energy storage system. The guaranteed commercial operation date is December 31, 2026. The term of the agreement is 20 years.

Further Information

A copy of the Authority's most recent Annual Report may be obtained from the Authority, 1160 Nicole Court, Glendora, California 91740. Each of the Authority and the Department maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2024 Series A Bonds.

DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS

State Legislation and Regulatory Proceedings

A number of bills affecting the electric utility industry have been introduced or enacted by the California Legislature in recent years. In general, these bills regulate greenhouse gas emissions and provide for greater investment in energy efficiency and environmentally friendly generation and storage alternatives, principally through more stringent renewable resource portfolio standard requirements and more aggressive emissions reduction programs to combat the effects of climate change. More recently, enacted legislation has also focused on addressing issues relating to wildfire risks and occurrences in California, including imposing certain requirements on electric utilities in connection with planning for and mitigating such occurrences and risks. The following is a brief summary of certain of these bills that have been enacted. This discussion does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof.

Greenhouse Gas Emissions – Background; Global Warming Solutions Act. In September 2006, then-Governor Schwarzenegger signed into law Assembly Bill 32, the Global Warming Solutions Act of 2006 (hereinafter, the "GWSA"), which became effective on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of returning to 1990 greenhouse gas emission levels by 2020 as prescribed by Executive Order S-3-05 of the Governor issued on June 1, 2005. In September 2016, then-Governor Brown signed into law Senate Bill 32 ("SB 32"), an amendment to the GWSA. SB 32, which became effective as law on January 1, 2017, codified a new interim statewide greenhouse gas emission reduction target, consistent with Executive Order B-30-15, signed by Governor Brown on April 29, 2015. SB 32 requires the California Air Resources Board ("CARB"), which, pursuant to the GWSA, is the designated state agency charged with monitoring and regulating sources of emissions of greenhouse gases, to ensure that statewide greenhouse gas emissions are reduced to at least 40% below the 1990 level no later than December 31, 2030.

Senate Bill 350 ("SB 350"), signed by then-Governor Brown in October 2015 (and additionally discussed under "*– Renewables Portfolio Standard*" below), requires CARB, in consultation with the California Public Utilities Commission (the "CPUC") and the California Energy Commission, to establish 2030 greenhouse gas emission targets for each electric utility in the State. At present, these targets are non-binding, and primarily intended to help the State measure progress toward the 2030 statewide goal outlined in SB 32. The targets, however, are an input to the integrated resource plans that are required of the State's 16 largest local publicly-owned electric utilities ("POUs"). See "*– Renewables Portfolio Standard*" below.

The GWSA also established an annual mandatory reporting requirement for all investor-owned utilities ("IOUs"), POUs, and other load-serving entities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to CARB, required CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a "cap-and-trade" program) and gave CARB the authority to enforce such regulations beginning in 2012. The Authority and the Department are complying with the applicable reporting requirements under the GWSA.

Assembly Bill 1279 ("AB 1279") established additional greenhouse-gas emission reduction goals. AB 1279 declares the policy of the State both to achieve net-zero greenhouse gas emissions as soon as possible, but no later than 2045, and achieve and maintain net negative greenhouse gas emissions thereafter, and to ensure that by 2045, Statewide anthropogenic greenhouse gas emissions are reduced to at least 85% below the 1990 levels. Under AB 1279, "net zero greenhouse gas emissions" means emissions of greenhouse gases to the atmosphere are balanced by removals of greenhouse gas emissions over a period of time. At present, these targets are non-binding, and primarily intended to help the State progress toward the 2045 Statewide goal outlined in AB 1279.

Greenhouse Gas Emissions – Cap-and-Trade Program. Pursuant to the GWSA, CARB has adopted a series of regulations implementing a cap-and-trade program. The initial cap-and-trade regulation became effective on January 1, 2012. Emission compliance obligations under the regulation began on January 1, 2013. The cap-and-trade program covers sources accounting for 85% of California's greenhouse gas emissions, the largest program of its type in the United States.

The cap-and-trade regulations impose aggregate emissions limitations on the electricity generation industry in California. The cap-and-trade regulations require all regulated entities to obtain and submit to CARB compliance instruments (allowances and/or offsets) with respect to greenhouse gas emissions relating to its State generation activities, as well as for imported electricity from dedicated out-of-state resources. The cap-and-trade program includes the distribution of carbon allowances equal to the annual emissions cap. The Project Participant, like other electric utilities, receives administrative allocations of allowances for some of its expected greenhouse gas emissions. Additional allowances are auctioned quarterly. Entities that emit greenhouse gases at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or on the secondary market from other covered entities with surplus allowances. IOUs are required to auction the allowances they received for free from CARB. This requirement also applies to POUs that sell electricity into the California Independent System Operator Corporation ("ISO") markets, other than sales of electricity from resources funded by municipal tax-exempt debt where the POU makes a matched purchase to serve its traditional retail customers. Utilities required to sell their allowances in the auctions are then required to purchase allowances to meet their compliance obligations, and use any remaining proceeds from the sale of their allocated allowances for the benefit of their ratepayers and to meet the goals of the GWSA. POUs that do not sell into the ISO markets, and those that sell into the ISO markets only electricity from resources funded by municipal tax-exempt debt, have three options (which are not mutually exclusive) once their allocated allowances have been distributed to them. They can (i) place allowances in their compliance accounts to meet compliance obligations, (ii) place allowances in the compliance account of a joint powers agency or public power utility that generates power on their behalf, and/or (iii) auction the allowances and use the proceeds to benefit their ratepayers and meet the goals of the GWSA.

The cap-and-trade program also allows covered entities to use offset credits for compliance (initially not exceeding 8% of a covered entity's compliance obligation through the end of 2020). Offsets can be generated by emission reduction projects in sectors that are not regulated under the cap-and-trade program. CARB has approved the following types of offset projects: urban forest projects, reforestation projects, destruction of ozone-depleting substances, livestock methane management projects, destruction of fugitive coal mine methane and rice cultivation practices. CARB will continue to consider additional and updated offset protocols, including international, sector-based offsets; CARB is also required to reform the offset program pursuant to AB 398 as discussed below.

On July 17, 2017, the California Legislature passed AB 398, extending the cap-and-trade program from 2021 to 2030. AB 398 passed both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, the distribution of free carbon allowances is continued for certain industrial sectors. However, AB 398 imposes stricter limits on the use of offset credits for compliance, with 4% of a covered entity's compliance obligation to be allowed to be satisfied with offsets from 2021 through 2025, and 6% thereafter. In addition, one-half of any such offsets will be required to be in California. Under AB 398, CARB was directed to address the following: establish a price ceiling, offer non-tradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance over-allocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. Under AB 398, CARB was directed to include cost containment provisions to keep allowance prices from rising too high and pushing business expansion outside of the state (referred to as "leakage"). AB 398 was passed in conjunction with AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities. Amendments to the cap-and-trade regulations to reflect the requirements of AB 398 have been adopted by CARB and went into effect on April 1, 2019.

California's cap-and-trade program is linked to the equivalent program in Quebec, Canada. The program may in future years be linked to additional Canadian provincial cap-and-trade programs, and possibly other U.S. state cap-and-trade programs. The Authority and the Department are unable to predict at this time the full impact of the cap-and-trade program over the long-term on the Department's electric utility or on the electric utility industry generally or whether any additional changes to the adopted program will be made.

Since the advent of the cap-and-trade program in 2012, regulations by CARB have provided the electric sector, including the Department, with sufficient allocated greenhouse gas allowances or credits to cover existing operations in meeting retail load obligations. The Project Participant may bank allocated allowances in its compliance account to satisfy a portion of its ongoing compliance obligations. The Project Participant may also buy or sell allowances in the quarterly auctions or on the bi-lateral market to meet its additional compliance obligations. The Project Participant could be adversely affected by future changes in the allowance allocation methodology or by future reductions in the quantity of allowances allocated to it under CARB regulations, if the greenhouse gas emissions of its resource portfolio are in excess of the allowances administratively allocated to it and it is required to purchase compliance instruments on the market to cover its emissions.

Greenhouse Gas Emissions – Emissions Performance Standard. Senate Bill 1368 ("SB 1368") became effective as law on January 1, 2007. SB 1368 provided for an emission performance standard ("EPS"), restricting new investments in baseload fossil fuel electric generating resources that exceed a specified rate of greenhouse gas emissions. SB 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs such as the Department. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide ("CO2") per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

As modified, the EPS regulations require a POU to post a notice of a public meeting at which its governing board will consider any expenditure over $2.5 million to meet environmental regulatory requirements at a non-EPS compliant baseload facility. In addition, each POU is required to file an annual notice identifying all investments over $2.5 million that it anticipates making during the subsequent 12 months on non-EPS compliant baseload facilities to comply with environmental regulatory requirements. This requirement is waived for any POU that has entered into a binding agreement to divest within five years of all baseload facilities exceeding the EPS. CEC staff has confirmed that the $2.5 million threshold applies to an individual investment by each utility, and not the combined investment of all participants in a project.

Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037") was signed by then Governor Schwarzenegger on September 29, 2005. It requires that each POU, including the Department, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost-effective, reliable and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs. The Project Participant is complying with such reporting requirements.

Assembly Bill 2021 ("AB 2021"), signed by then Governor Schwarzenegger on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter for a ten-year horizon. A subsequent amendment, Assembly Bill 2227, extended the time interval for establishing annual targets from every three years to every four years. The Project Participant has complied with this reporting requirement under AB 2021. The information obtained from the POUs from these reporting requirements is utilized by the CEC to present the progress made by the POUs towards the statewide goal to double energy efficiency savings in electricity and natural gas final end uses by 2030, to the extent doing so is cost effective, feasible, and does not adversely impact public health and safety, as prescribed in SB 350. In addition, the CEC can provide recommendations for improvement to assist each POU in achieving cost-effective, reliable, and feasible savings in conjunction with the established targets for reduction. See "– *Renewables Portfolio Standard*" below.

SB 350 further requires the CEC to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The CPUC is required to establish energy efficiency targets for electrical and gas corporations consistent with this goal, and specify programs that may be used to achieve the goal. POUs are required to establish annual targets for energy efficiency savings and demand reduction consistent with the goal and to report those targets to the CEC every four years for the next 10-year period. The bill provides guidance as to what measures qualify and requires an evaluation of feasibility and cost effectiveness in setting annual targets for those savings.

Biomass Legislation. Senate Bill 859 ("SB 859"), signed by then-Governor Brown in September 2016, requires IOUs and POUs that serve more than 100,000 customers to procure, through financial commitments of five years, their proportionate shares (based on the ratio of the utility's peak demand to the total statewide peak demand), of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. Senate Bill 901 ("SB 901"), signed into law in September 2018, requires POUs with certain biomass contracts to seek to extend their term five years past the original expiration date. The Authority has executed power purchase agreements to provide bioenergy to certain members that are subject to the procurement requirements of SB 859 and SB 901 (which includes the Department). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Projects of the Authority Not Financed by Bonds – Projects Currently Operating – *ARP-Loyalton Biomass Project*" and " – *Roseburg Biomass Project*." Senate Bill 1109 ("SB 1109") signed into law by Governor Newsom on September 16, 2022 (and effective on January 1, 2023) modifies SB 859's requirement, instead requiring IOUs and POUs that serve more than 100,000 customers to procure, by December 1, 2023, through financial commitments of five to 15 years, their proportionate shares (based on the ratio of the utility's peak demand to the total statewide peak demand), of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. However, such modified requirements under SB 1109 do not apply to a POU if it, either directly or through a joint powers authority, entered into the five-year financial commitments as previously required pursuant to SB 859 and those commitments include (1) a contract with a facility operator that was, on June 1, 2022, in bankruptcy or (2) a contract for a project that does not deliver energy to the POU. The requirements of SB 1109 do not apply to LADWP because LADWP, either directly or through the Authority, entered into the five-year financial commitments as previously required pursuant to SB 859 and the ARP-Loyalton Biomass Project was in bankruptcy on June 1, 2022, and the Roseburg Biomass Project does not deliver energy to LADWP. SB 1109 also modified SB 901's contract extension requirement instead requiring POUs with certain biomass contracts that expire before December 31, 2028, to seek to extend their term five years past the expiration date operative in 2022. These contract extension requirements, similarly, do not apply to LADWP under SB 1109.

Renewables Portfolio Standard. Senate Bill X1-2 ("SBX1-2"), the California Renewable Energy Resources Act, was signed into law by Governor Brown on April 12, 2011. SBX1-2 required each POU to adopt and implement a renewable energy resource procurement plan and established targets for three compliance periods for the procurement of at least the following amounts of electricity products from eligible renewable energy resources, which could include renewable energy certificates ("RECs"), as a proportion of total kilowatt hours sold to the utility's retail end-use customers: (i) over the 2011-2013 compliance period, an average of 20% of retail sales from January 1, 2011 to December 31, 2013, inclusive; (ii) over the 2014-2016 compliance period, a total equal to 20% of 2014 retail sales, 20% of 2015 retail sales, and 25% of 2016 retail sales; and (iii) over the 2017-2020 compliance period, a total equal to 27% of 2017 retail sales, 29% of 2018 retail sales, 31% of 2019 retail sales, and 33% of 2020 retail sales. The governing boards of POUs are responsible for implementing the requirements of SBX1-2, rather than the CPUC, as is the case for the IOUs. In addition, the CEC was given certain enforcement authority for POUs and CARB was given the authority to set penalties. The CEC has developed detailed rules to implement SBX1-2, and has adopted regulations for the enforcement of the RPS program requirements for POUs, which regulations have been subsequently amended from time to time.

SB 350, the Clean Energy and Pollution Reduction Act of 2015, was signed into law by then Governor Brown on October 7, 2015. SB 350, as enacted, establishes an RPS target of 50% by December 31, 2030 for the amount of electricity generated and sold to retail customers from eligible renewable energy resources for retail sellers and POUs, including interim targets of (i) 40% by the end of the 2021-2024 compliance period, (ii) 45% by the end of the 2025-2027 compliance period and (iii) 50% by the end of the 2028-2030 compliance period.

SB 350 requires each retail seller of electricity (including IOUs, most POUs above a certain size threshold, community choice aggregators and energy service providers) to provide a renewable energy procurement plan on an annual basis, and to file an integrated resource plan ("IRP") at least once every five years, commencing no later than January 1, 2019, for CEC review. POUs with an annual electrical demand exceeding 700 gigawatt hours (as determined on a three-year average commencing January 1, 2013) are subject to this requirement, which applies to the State's 16 largest POUs. The governing body of the POU is responsible for adopting the IRP, subject to review by the CEC, which can recommend modifications to correct any shortcomings. This IRP is required to include the affected utility's plans to meet the 2030 interim emissions reductions goal set by CARB. The Project Participant has approved and adopted an integrated resource plan, and the CEC has determined that each of those plans is complete and consistent with the SB 350 requirements.

Senate Bill 100 ("SB 100"), the 100 Percent Clean Energy Act of 2018, was signed into law by then-Governor Brown in September 2018. SB 100 accelerates the State's RPS target as established by SB 350 from 50% by 2030 to 60% by 2030 and sets a goal of 100% "clean energy" by the year 2045. SB 100 requires retail electric sellers and local publicly-owned electric utilities to procure a minimum quantity of electric products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027 and 60% of retail sales by December 31, 2030. SB 100 further establishes a State policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. On the last day of the legislative session, after the passage of SB 100 in both the State Assembly and the State Senate, the bill's author, Senator Kevin de Leon, filed a "Letter to the Journal" clarifying the intent of SB 100, stating that "SB 100 does not seek to require retail sellers of electricity to default on existing contractual obligations to deliver electricity to California customers from existing zero-carbon generating facilities." This clarification allows existing nuclear resources (such as the Palo Verde Nuclear Generating Station) and large hydropower resources (such as Hoover Dam) to help meet the policy standard set forth in SB 100 that eligible renewable and zero-carbon resources supply 100% of retail sales of electricity by December 31, 2045.

In December 2020, the CEC adopted regulations to update the RPS Enforcement Procedures for Publicly Owned Utilities, including to update regulations amended by both SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350, pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of renewables procurement must be for a duration of 10 years or more. The regulations implement the new RPS procurement requirements for the compliance periods between 2021 and 2030, establish soft procurement targets for the intervening years of the compliance periods to demonstrate reasonable progress in meeting the RPS procurement target for the compliance periods, and establish three-year compliance periods beginning after 2030. The regulations also specify standards for 10-year procurement contracts to meet the long-term procurement requirement.

Senate Bill 1020 ("SB 1020"), the Clean Energy, Jobs, and Affordability Act of 2022, signed into law by Governor Newsom on September 16, 2022 (and effective on January 1, 2023), revises SB 100's State policy on eligible renewable energy resources and zero-carbon resources supply. Under the revised State policy, eligible renewable energy resources and zero-carbon resources would supply (i) 90% of all retail sales of electricity to California end-use customers by December 31, 2035, (ii) 95% of all retail sales of electricity to California end-use customers by December 31, 2040, (iii) 100% of all retail sales of electricity to California end-use customers by December 31, 2045, (iv) and 100% of electricity procured to serve all state agencies by December 31, 2035. SB 100 had expressly excluded consideration of the energy, capacity, or any attribute from the Diablo Canyon Unit 1 and Unit 2 nuclear generating facilities in meeting the State's eligible renewable and zero-carbon resources supply policies. SB 1020 eliminates that exclusion.

Legislation Relating to Wildfires; Related Risks. Senate Bill 1028 ("SB 1028") was signed into law by then-Governor Brown in September 2016. SB 1028 requires that each POU and each electric cooperative in the State construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 requires the governing board of each POU to determine, based on historical fire data and local conditions, and in consultation with the fire departments or other entities responsible for the control of wildfires within the geographical area where the utility's overhead electrical lines and equipment are located, whether any portion of that geographical area has a significant risk of wildfire resulting from those electrical lines and equipment, and if so, to present for board approval wildfire mitigation measures the utility intends to undertake to minimize the risk of its overhead electrical lines and equipment causing a catastrophic wildfire.

SB 901, signed into law by then-Governor Brown in September 2018, amends certain provisions of SB 1028 requiring POUs and electric cooperatives to prepare wildfire mitigation measures if the utilities' overhead electrical lines and equipment are located in an area that has a significant risk of wildfire resulting from those electrical lines and equipment. Under SB 901, each POU or electric cooperative was required to prepare a wildfire mitigation plan before January 1, 2020. SB 901 requires the wildfire mitigation plan to be updated annually thereafter. SB 901 requires specified information and elements to be considered as necessary, at minimum, in the wildfire mitigation plan. The POU or electric cooperative is required to present each wildfire mitigation plan in an appropriately noticed public meeting, and to accept comments on its wildfire mitigation plan from the public, other local and state agencies, and interested parties. In addition, SB 901 requires the POU or electric cooperative to contract with a qualified independent evaluator with experience in assessing the safe operation of electrical infrastructure to review and assess the comprehensiveness of its wildfire mitigation plan. The report of the independent evaluator is to be made available to the public and to be presented at a public meeting of the POU's governing board.

Assembly Bill 1054 ("AB 1054") was signed into law by Governor Newsom on July 12, 2019. AB 1054 was enacted as an urgency statute to take effect immediately. AB 1054 establishes a Wildfire Fund of approximately $21 billion to provide liquidity for IOUs to facilitate payment of eligible, uninsured third-party damage claims resulting from future catastrophic wildfires. POUs, including the Department, are not eligible to receive funding from the Wildfire Fund. AB 1054 revises the cost recovery review of wildfire costs and expenses for IOUs before the CPUC, and establishes safety certification protocols that IOUs must meet in order to participate in the Wildfire Fund. AB 1054 provides for a cap on an IOU's obligations to reimburse the Wildfire Fund and a presumption of reasonableness if a utility develops and maintains a valid safety certification. To receive the safety certification from the CPUC, the IOU must develop and implement an approved wildfire mitigation plan, implement the findings of its safety culture assessments, establish a safety committee of its board of directors, establish board level reporting to the CPUC on safety issues, and adopt a compensation structure tied to safety performance, among other requirements. The major IOUs in California are participants in the Wildfire Fund.

AB 1054 expands on the existing requirements established under SB 901 for POUs to develop and implement wildfire mitigation plans. AB 1054 also establishes the California Wildfire Safety Advisory Board (the "Wildfire Advisory Board"), a seven member board appointed by the Governor (five members), the Speaker of the State Assembly (one member) and the State Senate Committee on Rules (one member). The Wildfire Advisory Board advises the Office of Energy Infrastructure Safety on electrical corporations' wildfire mitigation plans, requirements for these plans, and other wildfire safety matters. Additionally, the Wildfire Advisory Board reviews the wildfire mitigation plans submitted by POUs and electrical corporations as discussed in more detail below. The Wildfire Advisory Board also serves as an additional forum for the public to provide input on the important topic of wildfire safety. AB 1054 requires each POU to update its plan annually and to comprehensively revise its plan at least once every three years. Under AB 1054, the Wildfire Advisory Board is required to provide comments and an advisory opinion regarding the content and sufficiency of plans and to make recommendations on how to mitigate wildfire risks. The Project Participant has prepared and submitted wildfire mitigation plans in accordance with the provisions of SB 901 and AB 1054 as required.

A number of significant wildfires have occurred in California every year since 2017. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by the utility's infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County* (2019) 7 Cal.5th 1091, 446 P.3d 304, involving damages related to sewage overflows from a city sewer system, the California Supreme Court held that to succeed on an inverse condemnation claim, a property owner must demonstrate that the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. None of SB 1028, SB 901 or AB 1054 addresses the existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions addresses California's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry, including the Department.

Impact of California Energy Market Developments

The effect of the developments in the California energy markets described above on the Authority and the Department cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors that affect both the supply and demand for and cost of electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet demand at all hours, the availability and cost of renewable energy, the impact of economy-wide greenhouse gas emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impacts of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). See "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY." This price volatility may contribute to greater volatility in the revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect a Project Participant's financial condition. The Project Participant undertakes resource planning and risk management activities and manage their respective resource portfolios to mitigate such price volatility and spot market rate exposure.

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 ("EPAct 2005"), FERC was given refund authority over POUs if they sell into short-term markets, like the ISO markets, and sell eight million MWhs or more of electric energy on an annual basis. In addition, FERC was given authority over the behavior of market participants. Under FERC's authority it can impose penalties on any seller for using a manipulative or deceptive device, including market manipulation, in connection with the purchase or sale of energy or of transmission service. The Commodity Futures Trading Commission also has jurisdiction to enforce certain types of market manipulation or deception claims under the Commodity Exchange Act.

EPAct 2005 authorized FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAct 2005 also required the creation of an Electric Reliability Organization ("ERO") to establish and enforce, under FERC supervision, mandatory reliability standards ("Reliability Standards") to increase system reliability and minimize blackouts. Failure to comply with such Reliability Standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards. As described above, EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval. The Reliability Standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each Reliability Standard. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation ("NERC") as the ERO. Many Reliability Standards have since been approved by FERC. Such standards pertain not only to the planning, operations, and maintenance of Bulk-Power System facilities, but also to the cyber and physical security of certain critical facilities.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC ("Regional Entities"), such as the WECC, may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce them. Potential monetary sanctions include fines of up to $1 million per violation per day. FERC Order 693 further provided the ERO and Regional Entities with the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.

Federal Regulation of Transmission Access

EPAct 2005 authorizes FERC to compel "open access" to the transmission systems of certain utilities that are not generally regulated by FERC, including municipal utilities if the utility sells more than four million MWhs of electricity per year. Under open access, a transmission provider must allow all customers to use the system under standardized rates, terms and conditions of service.

FERC Order No. 888 requires the provision of open access transmission services on a nondiscriminatory basis by all "jurisdictional utilities" (which, by definition, does not include municipal entities like the Department) by requiring all such utilities to file Open Access Transmission Tariffs ("OATTs"). Order No. 888 also requires "non-jurisdictional utilities" (which, by definition, does include the Department) that purchase transmission services from a jurisdictional utility under an open access tariff and that own or control transmission facilities to provide open access service to the jurisdictional utility under terms that are comparable to the service that the non-jurisdictional utility provides itself. Section 211A of EPAct 2005 authorizes, but does not require, FERC to order unregulated transmission utilities to provide transmission services. Specifically, FERC may require an unregulated transmitting utility to provide access to their transmission facilities (1) at rates that are comparable to those that the unregulated transmitting utility charges to itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself that are not unduly discriminatory or preferential.

On February 16, 2007, FERC issued Order 890, which concluded that reform of its pro forma OATT was necessary to reduce the potential for undue discrimination and provide clarity in the obligations of transmission providers and customers. Significantly, in Order 890 FERC stated that it will implement its authority under Section 211A with respect to unregulated transmitting utilities on a case-by-case basis and retain the current reciprocity provisions.

On July 21, 2011, FERC issued Order 1000, which among other things requires public utility (jurisdictional) transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and that incorporates a regional and inter-regional cost allocation methodology. Further, FERC states that it has the authority to allocate costs to beneficiaries of transmission services, even in the absence of a contractual relationship between the owner of the transmission facilities and the beneficiary. Under EPAct 2005, FERC may not require municipal utilities to join regional transmission organizations, in which participating utilities allow an independent entity to oversee operation of the utilities' transmission facilities. FERC has stated, however, that FERC expects such utilities to participate in the regional processes for transmission planning and that FERC will pursue associated complaints against such utilities on a case-by-case basis.

At its April 2022 meeting, FERC issued a Notice of Proposed Rulemaking that would, if adopted, result in reforms to the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. The Notice follows input FERC sought from interested parties on a variety of reforms aimed at expanding the nation's transmission grid to accommodate the surge of renewable generation expected in the next two decades to achieve aggressive decarbonization goals of the Biden Administration and many states. The Notice addresses reforms to transmission planning and cost allocation.

Federal Policy on Cybersecurity

On February 13, 2013, then President Obama issued the Executive Order "Improving Critical Infrastructure Security" (the "Infrastructure Security Executive Order"). Among other things, the Infrastructure Security Executive Order called for improved information sharing and processing of security clearances for owners and operators of critical infrastructure. The Infrastructure Security Executive Order further required the Secretary of Commerce to direct the National Institute of Standards and Technology ("NIST") to lead the development of a framework ("Framework") to reduce cyber risks to critical infrastructure. The voluntary Framework will continue to be updated and improved as industry provides feedback on implementation.

The Cybersecurity Information Sharing Act of 2015 was signed into law on December 18, 2015 as part of the year-end Omnibus Appropriations Act. It creates an industry-supported, voluntary cybersecurity information sharing program that encourages both public and private sector entities to share cyber-related threat information. The Authority supported passage of the bill.

In September 2018, then President Trump signed the "National Cyber Strategy," which sought to update the nation's cybersecurity strategy for the first time in 15 years – and identified "energy and power" as one of the seven key areas for protection. FERC has also sought to expand reporting rules for incidents involving attempts to compromise operation of the electric grid and address supply chain cybersecurity risks.

In March of 2023, the Biden administration adopted the 2023 National Cybersecurity Strategy. The 2023 National Cybersecurity Strategy replaces but continues momentum on many of the priorities of the 2018 National Cyber Strategy. The 2023 National Cybersecurity Strategy seeks to build and enhance collaboration around five pillars: (1) Defend Critical Infrastructure; (2) Disrupt and Dismantle Threat Actors; (3) Shape Market Forces to Drive Security and Resilience; (4) Invest in a Resilient Future; and (5) Forge International Partnerships to Pursue Shared Goals.

Environmental Issues

General. Electric utilities are subject to continuing environmental regulation. Federal, State and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any facilities or projects of the Authority or the Department will remain subject to the laws and regulations currently in effect, will always be in compliance with future laws and regulations or will always be able to obtain all required operating permits. In addition, the election of new administrations, including the President of the United States, could impact substantially the current environmental standards and regulations and other matters described herein. For example, President Biden issued an executive order requiring agencies to consider suspending, revising or rescinding multiple environmental standards and regulations imposed during the prior administration. An inability to comply with environmental standards could result in, for example, additional capital expenditures, reduced operating levels or the shutdown of individual units not in compliance. In addition, increased environmental laws and regulations may create certain barriers to new facility development, may require modification of existing facilities and may result in additional costs for affected resources.

Greenhouse Gas Regulations Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates greenhouse gas emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, greenhouse gases are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies ("BACT") to control emissions at a facility. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. Greenhouse gases from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

In May 2023, the EPA proposed new regulations under the Clean Air Act that would establish greenhouse gas emission limits, based on pollution control technology or lower-carbon fuels, for new gas plants, existing gas plants, and existing coal plants, as specified. The proposed rule is not yet final.

Air Quality – National Ambient Air Quality Standards. The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards ("NAAQS") for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the applicable standard and become an "attainment area." The EPA periodically reviews the NAAQS for various air pollutants and has in recent years increased, or proposed to increase, the stringency of the NAAQS for certain air pollutants. These developments may result in stringent permitting processes for new sources of emissions and additional state restrictions on existing sources of emissions, such as power plants.

In addition, the U.S. Supreme Court found in its review of *EPA v. EME Homer City Generation*, LP that the EPA has authority to impose a Cross-State Air Pollution Rule (the "Transport Rule") which curbs air pollution emitted in upwind states to facilitate downwind attainment of three NAAQS. On November 26, 2014, the EPA proposed to strengthen the stringency of the NAAQS for ozone by lowering the existing ozone standard of 75 parts per billion ("ppb") to between 65 and 70 ppb, although the EPA also sought public comment on a standard as low as 60 ppb. On October 1, 2015, the EPA issued its final rule, lowering the ozone standard to 70 ppb. Legal challenges to the final rule were filed by a number of states and industry groups. On March 12, 2018, a federal district judge in Northern California ordered the EPA to complete the strengthened 2015 ozone standard designations later in 2018. The EPA noticed a final rule on December 6, 2018 implementing ozone NAAQS for non-attainment areas and addressing state implementation plan requirements. That rule became effective on February 4, 2019.

On July 15, 2020, the EPA announced a proposed decision to retain the existing 70 ppb ozone standard. The decision was finalized on December 7, 2020. In August 2023, the EPA announced a new review of the ozone NAAQS to support consideration of new information and advice.

On June 10, 2021, the EPA announced that it will reconsider the previous administration's decision to retain the particulate matter NAAQS, which were last strengthened in 2012. The EPA stated that it is reconsidering the previous administration's December 2020 decision to retain existing standards because available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the Clean Air Act. While some particulate matter is emitted directly from sources such as construction sites, unpaved roads, fields, smokestacks or fires, most particles form in the atmosphere as a result of complex reactions of chemicals such as sulfur dioxide and nitrogen oxides, which are pollutants emitted from power plants and other sources. On January 6, 2023, the EPA proposed regulations imposing tighter limits on particulate matter emissions. The proposed rule is not yet final.

Mercury and Air Toxics Standards. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants, including mercury. On February 16, 2012, the EPA finalized a rule, the Mercury and Air Toxics Standards ("MATS"), establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards, or "NSPS") and 112 (toxics program) of the Clean Air Act. The rule was subsequently amended in 2013 and 2014. Under section 111 of the Clean Air Act, the MATS rule revised the standards that new and modified facilities, including coal- and oil-fired power plants, must meet for particulate matter, sulfur dioxide, and nitrogen oxide. Under section 112, the MATS rule set new toxics standards limiting emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid, from existing and new power plants larger than 25 MW that burn coal or oil. Power plants would have up to four years to meet these standards. While many plants already meet some or all of these revised standards, some plants would be required to install new equipment to meet the standards. The rule has minimal impact to the Authority and the Department. IPP, which has coal-fired power plants, did not have to install control technology, and the EPA has deemed the IPP units as low-emitting units. IPP is subject to periodic testing, work practice standards and recordkeeping requirements as a result of the rule. On July 17, 2020, the EPA finalized revisions to the electronic reporting requirements for MATS that revised and streamlined the reporting requirements and provided enhanced access to MATS data, without imposing new monitoring requirements. In April 2023, the EPA published a proposed rule that would modify regulation of coal- and oil-fired power plants, including further restricting their emissions and changing emissions monitoring requirements. The proposed rule is not yet final.

Effluent Limitations Guidelines and Standards. On June 7, 2013, the EPA proposed to set technology-based effluent limitations guidelines and standards for metals and other pollutants in wastewater discharged from steam electric power plants. The proposal would cover wastewater associated with several types of equipment and processes, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control and gasification of fuels. The EPA considered best management practices for surface impoundments containing coal combustion residuals. The EPA proposed four preferred alternatives for regulating wastewater discharges. The stringency of controls, types of waste streams covered, and the costs varied among the four alternatives. On September 30, 2015, the EPA announced its final Steam Electric Effluent Limitation Guidelines to update the federal limits on toxic metals in discharge wastewater. On June 6, 2017, the Trump Administration announced that it was postponing certain compliance dates in the effluent limitation guidelines and standards for the new, more stringent steam electric point source category under the Clean Water Act until the EPA completes reconsideration of the 2015 rule. On May 2, 2018, the EPA noticed the Final 2016 Effluent Guidelines Program Plan, which identified one new rulemaking (and the associated schedule) for the steam electric power generating point source category. The proposed rule was published in November 2019, a public hearing on the proposed rule was held on December 19, 2019, and the final rule for steam electric power generation point source was published on August 31, 2020. On August 3, 2021, the EPA announced a planned-rulemaking to strengthen certain discharge limits in the steam electric power generating category. The EPA published a proposed rule in March 2023. The rule was finalized in May 2023.

Changing Laws and Requirements Generally

Congress has considered and is considering numerous bills addressing domestic energy policies and various environmental matters, including bills relating to energy supplies and financial incentives for development, climate change and reduction or elimination of net carbon dioxide emission attributable to the electricity grid and the economy more generally. Many of these bills, if enacted into law, could have a material impact on the Authority, the Department and the electric utility industry generally. In light of the variety of issues affecting the utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements, and cybersecurity is also possible. However, the Authority and the Department are unable to predict the outcome or potential impacts of any possible legislation on the Department's electric utility at this time.

Other Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors discussed above, such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements other than those described above (including those affecting nuclear power plants or potential new energy storage requirements), (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) effects on the integration and reliability of power supply from the increased usage of renewables, (d) changes resulting from a national energy policy, (e) effects of competition from other electric utilities (including increased competition resulting from a movement to allow direct access or expanded community choice aggregation or from mergers, acquisitions, and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity, (f) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many IOUs, (g) increased competition from independent power producers and marketers, brokers and federal power marketing agencies, (h) "self-generation" or "distributed generation" (such as microturbines, fuel cells and solar installations) by industrial and commercial customers and others, (i) issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission service from transmission line projects financed with outstanding tax-exempt obligations and, as of January 1, 2018, the loss of the ability to undertake tax-exempt advance refundings, (j) effects of inflation on the operating and maintenance costs of an electric utility and its facilities, (k) changes from projected future load requirements, (l) increases in costs and uncertain availability of capital, (m) shifts in the availability and relative costs of different fuels (including the cost of natural gas and nuclear fuel), (n) changes in the electric market structure for neighboring electric grids, such as the energy imbalance market operated by the ISO, (o) sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the past in California, (p) issues relating to risk management procedures and practices with respect to, among other things, the purchase and sale of natural gas, energy and transmission capacity, (q) other legislative changes, voter initiatives, referenda and statewide propositions, (r) effects of the changes in the economy, population and demand of customers within a utility's service area, (s) effects of possible manipulation of the electric markets, (t) acts of terrorism or cyber-terrorism impacting a utility and/or significant load customers, (u) changes to the climate; (v) natural disasters or other physical calamities, including, but not limited to, earthquakes, droughts, severe weather, floods and wildfires, and potential liabilities of electric utilities in connection therewith, and (w) adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk. Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

The Authority is unable to predict what impacts such factors will have on the business operations and financial condition of the Department's electric system, but the impacts could be significant. Although this Official Statement includes a brief discussion of certain of these factors, this discussion does not purport to be comprehensive or definitive; and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain, and potential purchasers of the 2024 Series A Bonds should obtain and review such information.

CONSTITUTIONAL LIMITATIONS IN CALIFORNIA AFFECTING FEES AND CHARGES IMPOSED BY THE PROJECT PARTICIPANTS

The following is a discussion of certain limitations under provisions of the California Constitution that may affect the rates, fees and charges imposed by the Departments for the electric services they provide.

Proposition 218 and Proposition 26

Proposition 218, a State ballot initiative known as the "Right to Vote on Taxes Act," was approved by the voters of the State of California on November 5, 1996. Proposition 218 added Articles XIIIC and XIIID to the State Constitution. Article XIIIC imposes a majority voter approval requirement on local governments (including the Departments) with respect to taxes for general purposes, and a two-thirds voter approval requirement with respect to taxes for special purposes. Article XIIID creates additional requirements for the imposition by most local governments of general taxes, special taxes, assessments and "property-related" fees and charges. Article XIIID explicitly exempts fees for the provision of electric service from the provisions of such article.

Article XIIIC expressly extends the people's initiative power to the reduction or repeal of local taxes, assessments, and fees and charges imposed prior to its effective date (November 1996). The California Supreme Court held in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal.4th 205 (2006) that, under Article XIIIC, local voters by initiative may reduce a public agency's water rates and delivery charges, as those are property-related fees or charges within the meaning of Article XIIID, and noted that the initiative power described in Article XIIIC may extend to a broader category of fees and charges than the property-related fees and charges governed by Article XIIID. Moreover, in the case of *Bock v. City Council of Lompoc*, 109 Cal.App.3d 52 (1980), the Court of Appeal determined that an electric rate ordinance was not subject to the same constitutional restrictions that are applied to the use of the initiative process for tax measures so as to render it an improper subject of the initiative process. Thus, electric service charges (which are expressly exempted from the provisions of Article XIIID) may be subject to the initiative provisions of Article XIIIC, thereby subjecting such fees and charges to reduction by the electorate. The Authority believes that even if the electric rates of the Departments are subject to the initiative power, under Article XIIIC or otherwise, the electorate of the Departments would be precluded from reducing electric rates and charges in a manner materially and adversely affecting the payment of the 2024 Series A Bonds by virtue of the "impairment of contracts clause" of the United States Constitution.

The California electorate approved Proposition 26 at the November 2, 2010 election, amending Article XIIIC of the California Constitution. Proposition 26 was designed to supplement tax limitations California voters adopted when they approved Proposition 13 in 1978, and Proposition 218 in 1996. Proposition 26 applies by its terms to any levy, charge or exaction imposed, increased or extended by a local government on or after November 3, 2010. Proposition 26 deems any such levy, charge or fee to be a "tax", requiring voter approval under Article XIIIC unless it comes within one of the listed exceptions. Proposition 26 expressly excludes from its definition of a "tax," among other things, a "charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product." Proposition 26 is applicable to the electric rates of governmental entities such as the Departments; therefore, newly adopted rates must conform to its requirements.

Proposition 26 is subject to interpretation by California courts, including the extent to which it is applicable to pre-existing electric rates and general fund transfers. A number of lawsuits have been filed against public agencies in California relating to electric utility fund transfers. In *Citizens for Fair REU Rates v. City of Redding* (filed on January 20, 2015 and modified on February 19, 2015), for example, the California Court of Appeal considered a ratepayer challenge to a "payment in lieu of taxes" (or "PILOT") required by the City of Redding to be made by its electric utility as an annual budgetary transfer amount without voter approval. The city's PILOT was designed to compensate the general fund for the costs of services that other city departments provide to the electric utility. The amount of the PILOT was equivalent to the ad valorem taxes the electric utility would have had to pay if the electric utility were privately owned. The suits alleged that the PILOT was passed through to the city's electric utility customers as part of the rates and charges for electric service in excess of the reasonable costs to the city of providing electric service. The Court of Appeal determined that Proposition 26 has no retroactive effect as to local taxes that existed prior to November 3, 2010, but found that since the PILOT was subject to the City Council's recurring discretion, the PILOT did not escape the purview of Proposition 26. The Court of Appeal concluded that the PILOT constituted a "tax" under Proposition 26 for which the city must secure voter approval unless the city proved that the amount collected was necessary to cover the reasonable costs to the city of providing electric service. On April 29, 2015, the California Supreme Court granted review of the decision of the Court of Appeal. The California Supreme Court rendered its decision on August 27, 2018, reversing the judgment of the Court of Appeal. The California Supreme Court determined that the budgetary transfer from the City of Redding electric utility to the city's general fund, calculated by using the PILOT, itself is not the type of exaction that is subject to Article XIIIC of the California Constitution. The court reasoned that it is only the City of Redding electric utility rate, not the PILOT, that is imposed on customers for electric service. The California Supreme Court concluded that because the total retail rate revenue of the electric utility was insufficient to cover the electric utility's uncontested operating expenses (other than the PILOT) in the years at issue, the challenged rate did not exceed the reasonable costs of providing electric service, and therefore did not constitute a tax.

The Authority and the Department are unable to predict at this time how Propositions 218 and 26 will ultimately be interpreted by the courts in the context of the Department's electric system rates or what the ultimate impact of Propositions 218 or 26 will be.

Other Initiatives

Articles XIIIC and XIIID and the amendments effected thereto by Proposition 26 were adopted as measures that qualified for the ballot pursuant to California's initiative process. From time to time, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be adopted affecting the Authority's and/or the Department's revenues or operations. Neither the nature and impact of these measures nor the likelihood of qualification for ballot or passage can be predicted by the Authority or the Department.

A voter initiative entitled "The Taxpayer Protection and Government Accountability Act" ("Initiative 1935") was recently determined to be eligible for the November 2024 Statewide general election and will be certified as qualified for the ballot in such election, unless withdrawn by its proponent prior to June 27, 2024 or a pending court challenge is successful in preventing Initiative 1935 from appearing on the ballot. Were it to be adopted by the voters in the Statewide general election, Initiative 1935 would amend the California Constitution to provide, among other things, that charges for services or product provided directly to the payor (such as charges for electricity) are "taxes" subject to voter approval unless the local government can prove by clear and convincing evidence that the charge is reasonable and does not exceed the "actual cost" of providing the service or product, defined as "(i) the minimum amount necessary to reimburse the government for the cost of providing the service or the product to the payor, and (ii) where the amount charged is not used by the government for any purpose other than reimbursing that cost." If adopted, Initiative 1935 would be subject to judicial interpretation. Neither the Authority nor the Department are able to predict whether and how Initiative 1935, if adopted, would be interpreted by the courts, and there can be no assurance that any such interpretation or application would not have an adverse impact on the Department, its electric utility or the revenues of its electric utility.

LITIGATION

At the time of delivery of the 2024 Series A Bonds, an authorized officer of the Authority will certify to the effect that, to the knowledge of such officer, there is no litigation or other proceeding pending or threatened in any court, agency or other administrative body (either State of California or federal) restraining or enjoining the issuance, sale or delivery of the 2024 Series A Bonds or the collection of Revenues, or in any way questioning or affecting (i) the proceedings under which the 2024 Series A Bonds are to be issued, (ii) the validity of any provision of the 2024 Series A Bonds or the Indenture, (iii) the pledge by the Authority under the Indenture, (iv) the validity or enforceability of the Power Sales Agreement, (v) the legal existence of the Authority or the title to office of the present officials of the Authority, or (vi) the authority of the Authority to acquire the Project.

TAX MATTERS

[To be updated]

Federal Income Taxes

The Internal Revenue Code of 1986, as amended (the "Code"), imposes certain requirements that must be met subsequent to the issuance and delivery of the 2024 Series A Bonds for interest thereon to be and remain excluded from gross income for federal income tax purposes. Noncompliance with such requirements could cause the interest on the Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the 2024 Series A Bonds. Pursuant to the Indenture and the Tax and Nonarbitrage Certificate (the "Tax Certificate"), the Authority has covenanted to comply with the applicable requirements of the Code in order to maintain the exclusion of the interest on the 2024 Series A Bonds from gross income for federal income tax purposes pursuant to Section 103 of the Code. In addition, the Authority has made certain representations and certifications in the Indenture and the Tax Certificate. Special Tax Counsel will not independently verify the accuracy of those representations and certifications.

In the opinion of Nixon Peabody LLP, Special Tax Counsel, under existing law and assuming compliance with the aforementioned covenant, and the accuracy of certain representations and certifications made by the Authority described above, interest on the 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Code. Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code. Interest on the 2024 Series A Bonds will be taken into account in computing the alternative minimum tax imposed on certain corporations under the Code to the extent that such interest is included in the "adjusted financial statement income" of such corporations.

State Taxes

Special Tax Counsel is also of the opinion that interest on the 2024 Series A Bonds is exempt from personal income taxes of the State of California (the "State") under present State law. Special Tax Counsel expresses no opinion as to other State or local tax consequences arising with respect to the 2024 Series A Bonds nor as to the taxability of the 2024 Series A Bonds or the income therefrom under the laws of any state other than the State of California.

Original Issue Discount

Special Tax Counsel is further of the opinion that the excess of the principal amount of a maturity of the 2024 Series A Bonds over its issue price (i.e., the first price at which price a substantial amount of such maturity of the 2024 Series A Bonds was sold to the public, excluding bond houses, brokers or similar persons or organizations acting in the capacity of underwriters or wholesalers) (each, a "Discount Bond" and collectively the "Discount Bonds") constitutes original issue discount which is excluded from gross income for federal income tax purposes to the same extent as interest on the 2024 Series A Bonds. Further, such original issue discount accrues actuarially on a constant interest rate basis over the term of each Discount Bond and the basis of each Discount Bond acquired at such issue price by an initial purchaser thereof will be increased by the amount of such accrued original issue discount. The accrual of original issue discount may be taken into account as an increase in the amount of tax-exempt income for purposes of determining various other tax consequences of owning the Discount Bonds, even though there will not be a corresponding cash payment. Owners of the Discount Bonds are advised that they should consult with their own advisors with respect to the state and local tax consequences of owning such Discount Bonds.

Original Issue Premium

2024 Series A Bonds sold at prices in excess of their principal amounts are "Premium Bonds". An initial purchaser with an initial adjusted basis in a Premium Bond in excess of its principal amount will have amortizable bond premium which offsets the amount of tax-exempt interest and is not deductible from gross income for federal income tax purposes. The amount of amortizable bond premium for a taxable year is determined actuarially on a constant interest rate basis over the term of each Premium Bond based on the purchaser's yield to maturity (or, in the case of Premium Bonds callable prior to their maturity, over the period to the call date, based on the purchaser's yield to the call date and giving effect to any call premium). For purposes of determining gain or loss on the sale or other disposition of a Premium Bond, an initial purchaser who acquires such obligation with an amortizable bond premium is required to decrease such purchaser's adjusted basis in such Premium Bond annually by the amount of amortizable bond premium for the taxable year. The amortization of bond premium may be taken into account as a reduction in the amount of tax-exempt income for purposes of determining various other tax consequences of owning such 2024 Series A Bonds. Owners of the Premium Bonds are advised that they should consult with their own advisors with respect to the state and local tax consequences of owning such Premium Bonds.

Ancillary Tax Matters

Ownership of the 2024 Series A Bonds may result in other federal tax consequences to certain taxpayers, including, without limitation, certain S corporations, foreign corporations with branches in the United States, property and casualty insurance companies, individuals receiving Social Security or Railroad Retirement benefits, individuals seeking to claim the earned income credit, and taxpayers (including banks, thrift institutions and other financial institutions) who may be deemed to have incurred or continued indebtedness to purchase or to carry the 2024 Series A Bonds. Prospective investors are advised to consult their own tax advisors regarding these rules.

Interest paid on tax-exempt obligations such as the 2024 Series A Bonds is subject to information reporting to the Internal Revenue Service (the "IRS") in a manner similar to interest paid on taxable obligations. In addition, interest on the Bonds may be subject to backup withholding if such interest is paid to a registered owner that (a) fails to provide certain identifying information (such as the registered owner's taxpayer identification number) in the manner required by the IRS, or (b) has been identified by the IRS as being subject to backup withholding.

Special Tax Counsel is not rendering any opinion as to any federal tax matters other than those described in the opinion attached as Appendix E. Prospective investors, particularly those who may be subject to special rules described above, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the 2024 Series A Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

Changes in Law and Post Issuance Events

Legislative or administrative actions and court decisions, at either the federal or state level, could have an adverse impact on the potential benefits of the exclusion from gross income of the interest on the 2024 Series A Bonds for federal or state income tax purposes, and thus on the value or marketability of the 2024 Series A Bonds. This could result from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), repeal of the exclusion of the interest on the 2024 Series A Bonds from gross income for federal or state income tax purposes, or otherwise. It is not possible to predict whether any legislative or administrative actions or court decisions having an adverse impact on the federal or state income tax treatment of holders of the 2024 Series A Bonds may occur. Prospective purchasers of the 2024 Series A Bonds should consult their own tax advisors regarding the impact of any change in law on the 2024 Series A Bonds.

Special Tax Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the 2024 Series A Bonds may affect the tax status of interest on the 2024 Series A Bonds. Special Tax Counsel expresses no opinion as to any federal, state or local tax law consequences with respect to the 2024 Series A Bonds, or the interest thereon, if any action is taken with respect to the 2024 Series A Bonds or the proceeds thereof upon the advice or approval of other counsel.

RATINGS

S&P Global Ratings and Fitch Ratings, Inc. have assigned the 2024 Series A Bonds the credit ratings of "[__]" and "[__]," respectively. No application has been made to any other rating agency in order to obtain additional ratings on the 2024 Series A Bonds. Each credit rating should be evaluated independently of any other rating. Generally, a rating agency bases its rating on the information and materials furnished to it and on investigations, studies and assumptions of its own. A credit rating reflects only the view of the organization furnishing the same and any desired explanation of the significance of such rating should be obtained from the rating agency furnishing the same.

The above described ratings are not a recommendation to buy, sell or hold the 2024 Series A Bonds. There is no assurance that any such rating will continue for any given period or that it will not be revised downward or withdrawn entirely by the rating agency furnishing such rating, if in the judgment of such rating agency, circumstances so warrant. The Authority undertakes no responsibility to oppose any such revision or withdrawal. Any downward revision or withdrawal of a credit rating may have an adverse effect on the market price of the 2024 Series A Bonds.

UNDERWRITING

The 2024 Series A Bonds will be purchased jointly and severally for reoffering by J.P. Morgan Securities LLC and PNC Capital Markets LLC (the "Underwriters"), at an aggregate purchase price of $_________, representing the par amount of the 2024 Series A Bonds of $_________, plus [net] original issue premium of $_________, less the Underwriters' discount of $_________. The Underwriters will be obligated to purchase all of the 2024 Series A Bonds if any of the 2024 Series A Bonds are purchased.

The Underwriters may offer and sell the 2024 Series A Bonds to certain dealers (including dealers depositing 2024 Series A Bonds into investment trusts) and others at prices lower than the respective public offering prices stated or derived from information stated on the inside cover page hereof. The initial public offering prices may be changed from time to time by the Underwriters.

[Underwriter disclosures, if any.]

CERTAIN RELATIONSHIPS

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Under certain circumstances, the Underwriters and their respective affiliates may have certain creditor and/or other rights against the Authority and the Department in connection with such activities. The Underwriters and their respective affiliates have, from time to time, performed and may in the future perform, various investment banking services for the Authority, for which they received or will receive customary fees and expenses.

In the course of their various business activities, the Underwriters and their respective affiliates, may purchase, sell or hold a broad array of investments and actively traded securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of the Authority (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with the Authority.

The Underwriters and their respective affiliates may also communicate independent investment recommendations, market advice or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

MUNICIPAL ADVISOR

The Authority has retained PFM Financial Advisors LLC, Los Angeles, California, as Municipal Advisor (the "Municipal Advisor") in connection with the issuance of the 2024 Series A Bonds. The Municipal Advisor has not undertaken to make an independent verification or to assume responsibility for the accuracy, completeness, or fairness of the information contained in this Official Statement. The Municipal Advisor is an independent financial advisory firm and is not engaged in the business of underwriting, trading or distributing municipal securities or other public securities. The payment of the fees of the Municipal Advisor is contingent upon the issuance and delivery of the 2024 Series A Bonds.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 2024 Series A Bonds are subject to the approval of Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel. The form of opinion that Bond Counsel proposes to render with respect to the 2024 Series A Bonds is attached as Appendix D hereto. Certain other legal matters with respect to the Authority will be passed upon by its General Counsel, Christine Godinez, Esq., and by Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel. The form of opinion that Special Tax Counsel proposes to render with respect to the 2024 Series A Bonds is attached as Appendix E hereto. Bond Counsel will not address any of the tax aspects of the 2024 Series A Bonds. Certain legal matters will be passed upon for the Underwriters by their counsel, Hawkins Delafield & Wood LLP, Sacramento, California. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2024 Series A Bonds.

CONTINUING DISCLOSURE UNDERTAKING FOR THE 2024 SERIES A BONDS

Pursuant to the Continuing Disclosure Resolution of the Authority's Board of Directors, the Authority has agreed for the benefit of the registered owners and the "Beneficial Owners" of the 2024 Series A Bonds to provide certain financial information and operating data relating to the Authority and LADWP by not later than six months after the end of each of the Authority's fiscal years (presently, by each December 31) commencing with fiscal year 2023-24 (the "Annual Report"), and to provide notices of the occurrence of certain specified events with respect to the 2024 Series A Bonds. The Annual Report will be filed by or on behalf of the Authority with the Municipal Securities Rulemaking Board ("MSRB") through the MSRB's Electronic Municipal Market Access ("EMMA") system. The notices of such events will also be filed by or on behalf of the Authority with the MSRB through the EMMA system. The specific nature of the information to be contained in the Annual Report and the notices of events is set forth in the form of the Continuing Disclosure Resolution which is included in its entirety in Appendix C hereto. The Authority's continuing disclosure undertaking has been made in order to assist the Underwriters in complying with SEC Rule 15c2-12.

The Authority is in compliance in all material respects with its continuing disclosure undertakings for the last five years. During the last five years, the Authority has filed annual reports for between 13 and 16 different projects for which it has issued revenue bonds. In the last five years, although the Authority generally has routinely filed notices of known instances of rating changes in connection with its revenue bonds, two rating changes in each of 2022 and 2023 were inadvertently not updated. Filings have been posted with EMMA to update the ratings. Lastly, for the fiscal year 2019-20 annual report relating to the Authority's Magnolia Power Project A, Refunding Revenue Bonds, 2020-1 and 2020-3, the audited financial statements of the Anaheim Public Utilities Department were timely filed but inadvertently were not linked to all relevant CUSIP numbers. The Authority has since caused such information to be linked to all relevant CUSIP numbers. The Authority believes it has established processes to ensure it will continue to comply in all material respects with its continuing disclosure undertakings in the future.

AVAILABLE INFORMATION

Copies of the Authority's most recent audited financial statements and Annual Report, and copies of the form of the Power Sales Agreement and the Indenture are available from the Authority, 1160 Nicole Court, Glendora, California 91740.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By: ____
Interim Executive Director

THE PROJECT PARTICIPANT

THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

The following information concerning The Department of Water and Power of the City of Los Angeles (in this section, the "Department") and such Department's Power System, has been prepared by the Department for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Department or the Power System. A copy of the most recent audited financial statements of the Power System (the "Department's Power System Financial Statements") may be obtained from Peter Huynh, Assistant Chief Financial Officer and Treasurer of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012, and is also available on the Electronic Municipal Market Access ("EMMA") website of the Municipal Securities Rulemaking Board ("MSRB"), currently located at http://emma.msrb.org. The Department's Power System Financial Statements are incorporated herein by this reference. However, other information presented on such website or referenced therein other than the Department's Power System Financial Statements is not part of this Official Statement and is not by reference to such website incorporated herein.

GENERAL

The Department is the largest municipal utility in the United States and is a proprietary department of the City of Los Angeles (the "City"). Control of Power System assets and funds is vested with the Board of Water and Power Commissioners of the City of Los Angeles (the "Board"), whose actions are subject to review by the City Council of the City (the "City Council"). The Department is responsible for providing the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City. The City encompasses approximately 473 square miles and is populated by approximately 3.8 million residents.

Department operations began in the early years of the twentieth century. The first Board of Power Commissioners was established in 1902. Nine years later, the responsibilities for the provision of electricity and water within the City were given to the Los Angeles Department of Public Service (the "Department of Public Service"). The Department of Public Service was superseded in 1925 with passage of the 1925 Charter and the creation of the Department. The Department now operates under the Charter adopted in 2000. The operations and finances of the Water System are separate from those of the Power System.

A copy of the most recent official statement or offering memorandum prepared by the Department for the issuance of securities for its Power System may be obtained from Peter Huynh, Assistant Chief Financial Officer and Treasurer of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012, or is available from the MSRB through its EMMA system.

Charter Provisions

Pursuant to the Charter, the Board is the governing body of the Department and the General Manager of the Department (the "General Manager") administers the affairs of the Department.

The Charter provides that all revenue from every source collected by the Department in connection with its possession, management and control of the Power System is to be deposited in the Power Revenue Fund. The Charter further provides that the Board controls the money in the Power Revenue Fund and makes provision for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund. The procedure relating to the authorization of the issuance of bonds is governed by Section 609 of the Charter.

Section 245 of the Charter provides that, with certain exceptions, actions of City commissions and boards ("Board Action"), including the Board, do not become final until five consecutive City Council meetings convened in regular session have passed or a waiver of such period is granted by City Council. During those five City Council meetings (unless the waiver of such period has been granted), the City Council may, on a two-thirds vote, take up the Board Action. If the Board Action is taken up, the City Council may approve or veto the Board Action within 21 calendar days of taking up the Board Action. If the City Council takes no action to assert jurisdiction over the Board Action during those five meetings, the Board Action becomes final at the end of such period.

Board of Water and Power Commissioners

Under the Charter, the Board is granted the possession, management and control of the Power System. Pursuant to the Charter, the Board also has the power and duty to make and enforce all necessary rules and regulations governing the construction, maintenance, operation, connection to and use of the Power System and to acquire, construct, extend, maintain and operate all improvements, utilities, structures and facilities the Board deems necessary or convenient for purposes of the Department. The Mayor of the City appoints, and the City Council confirms the appointment of, members of the Board. The Board is traditionally selected from among prominent business, professional and civic leaders in the City. The members of the Board serve with only nominal compensation. Certain matters regarding the administration of the Department also require the approval of the City Council.

The Board is composed of five members. The current members of the Board are:

RICHARD KATZ, *President*. Mr. Katz was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 22, 2024. Mr. Katz was elected President of the Board on March 26, 2024. Mr. Katz is a long-time public servant and state policymaker with specific expertise in the areas of water, transportation, land use, and energy. He is the owner of Richard Katz Consulting Inc., a public policy and government relations firm based in Los Angeles. Mr. Katz previously served in the California State Assembly representing the North and East San Fernando Valley for sixteen years. After leaving the State Assembly, Mr. Katz was appointed to the State Water Resources Control Board, where he served for six years, occupying the water quality seat. Mr. Katz also served as a Senior Advisor on Energy and Water issues to Governor Gray Davis. He has previously served on the governing boards of the Los Angeles County Metropolitan Transportation Authority and Metrolink. Mr. Katz holds a Bachelor of Arts degree in political science (major) and history (minor) from San Diego State University.

GEORGE MCGRAW, *Vice President*. Mr. McGraw was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on June 20, 2023. Mr. McGraw was elected Vice President of the Board on March 26, 2024. Mr. McGraw serves as founder and CEO of DigDeep, the only water, sanitation and hygiene organization solely focused on the United States, developing education, research and infrastructure programs aimed at extending the human right to clean running water to every American. In this capacity, Mr. McGraw works with local government officials, policymakers and utility providers to innovate solutions to the problems of water and sanitation access in different areas of the nation. Mr. McGraw is an Ashoka Fellow, a member of the Aspen Global Leadership Network and former Social Entrepreneur in Residence at Stanford University. He holds a Master of Arts degree in International Law and the Settlement of Disputes from the United Nations University for Peace.

NURIT KATZ, *Commissioner*. Ms. Katz was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on December 6, 2022. She is the Chief Sustainability Officer for the University of California, Los Angeles ("UCLA"), where she has led the development of the University's first comprehensive sustainability plan and fosters collaboration across the leading public university to advance sustainability through education, research, operations, and community partnerships. For six years Ms. Katz also served as Executive Officer for Facilities Management at UCLA. She has over 15 years of teaching experience and is an Instructor for the UCLA Extension Sustainability Certificate Program. Ms. Katz also has taught for the UCLA Institute of Environment and Sustainability and prior to UCLA worked in environmental and outdoor education. She holds a Master of Business Administration degree and a master's degree in public policy from UCLA, and a Bachelor of Arts in environmental education from Humboldt State University. She is currently pursuing a PhD in ecology and evolutionary biology at UCLA and is a Trainee in the National Science Foundation Research Traineeship Innovation at the Nexus of Food, Energy, and Water Systems program.

MIA LEHRER, *Commissioner*. Ms. Lehrer was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on October 21, 2020. Ms. Lehrer is president and founder of Studio-MLA, a landscape architecture, urban design, and planning practice dedicated to advocacy by design with a vision to improve quality of life through landscape. She has served as an advisor to numerous public agencies, including the United States Fine Arts Commission under President Barack Obama, the Los Angeles Cultural Heritage Commission, and the Los Angeles Zoning Advisory Committee. Ms. Lehrer was a member of the team that delivered the Los Angeles River Revitalization Master Plan and the 2020 Upper Los Angeles River and Tributaries Master Plan. She also serves on the board for the Southern California Development Forum and in 2010 she was elevated to Fellow of the American Society of Landscape Architects. Ms. Lehrer holds a Bachelor of Arts degree from Tufts University and a Master of Landscape Architecture degree from the Harvard University Graduate School of Design.

WILMA J. PINDER, *Commissioner*. Ms. Pinder was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 8, 2024. Ms. Pinder is a former Los Angeles Assistant City Attorney. She served the city as a civil litigator and trial attorney for 30 years, 20 of those years were with the Water and Power Division of the City Attorney's Office. Ms. Pinder has been active with national, state and local bar associations, serving as a Board member on several. Ms. Pinder is a Life Fellow of the American Bar Foundation ("ABF") and served on its Board for 10 years. The ABF expands knowledge and advances justice through research on law and legal institutions. She has also served on alumni boards at the University of Southern California ("USC") and UCLA. Ms. Pinder is active in the greater Los Angeles area with a number of service-oriented groups. Ms. Pinder holds a Bachelor of Arts degree in psychology from USC, a Master of Science degree in psychology from Howard University, and a Juris Doctorate from UCLA School of Law. She is also trained in community mediation and dispute resolution.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. The management structure of the Department consists of three functional senior executive positions: Chief Operating Officer, Senior Assistant General Manager of the Power System and Chief Financial Officer. The Department's financial affairs are supervised by the Chief Financial Officer. The Power System is directed by the Senior Assistant General Manager of the Power System with an Executive Director for Construction, Maintenance and Operations, and an Executive Director for Planning, Engineering, and Technology Applications. Legal counsel is provided to the Department by the Office of the City Attorney of the City of Los Angeles.

Below are brief biographies of the Department's General Manager, Mr. Martin L. Adams, and other members of the senior management team for the Power System:

MARTIN L. ADAMS, *General Manager and Chief Engineer*. Mr. Adams was named Interim General Manager of the Department in July 2019 and confirmed as the General Manager and Chief Engineer by the City Council in September 2019. Prior to his appointment as General Manager, Mr. Adams served as the Chief Operating Officer of the Department since September 2016. In that capacity, he oversaw the Water System and Power System, along with other support organizations within the Department. Mr. Adams has more than 39 years of experience at the Department, where he started as an entry level engineer in the Water System, eventually leading the Water System as its Senior Assistant General Manager. During the course of his career, Mr. Adams worked throughout the Water System and was directly involved with the planning and implementation of major changes to water storage, conveyance, and treatment facilities to meet new water quality regulations. He has spent almost half of his career in system operations, including ten years as the Director of Water Operations in charge of the day-to-day operation and maintenance of the Los Angeles water delivery system, including the Los Angeles Aqueduct and other supply sources, pump stations, reservoirs, water treatment, and management of Water System properties. Mr. Adams received his Bachelor of Science degree in civil engineering from Loyola Marymount University in Los Angeles.

Mr. Adams has announced his retirement, which is expected to occur in the first half of 2024. The Mayor has announced that a nationwide recruitment process is being undertaken by the City for a successor General Manager. It is anticipated that Mr. Adams will continue to serve the Department while the City's recruitment process is ongoing until a successor is named.

ARAM BENYAMIN, *Chief Operating Officer*. Mr. Benyamin was named Chief Operating Officer of the Department in November 2022. In this role he oversees the Water System and Power System, along with other support organizations within the Department. Prior to rejoining the Department in November 2022, Mr. Benyamin was the Chief Executive Officer for Colorado Springs Utilities (a municipally-owned utility). He joined Colorado Springs Utilities in 2015 as the General Manager – Energy Supply and was named Chief Executive Officer in October 2018. Prior to joining Colorado Springs Utilities, Mr. Benyamin was the Department's Senior Assistant General Manager – Power System. Mr. Benyamin previously worked for the Department in various roles for over 30 years. He is a Professional Engineer with a Bachelor of Science degree in engineering from California State University, Los Angeles. Mr. Benyamin also has a master's degree in business administration from the University of La Verne and a master's degree in public of administration from California State University, Northridge.

ANN M. SANTILLI, *Chief Financial Officer*. Ms. Santilli was named Chief Financial Officer of the Department in May 2019. She had served as Interim Chief Financial Officer of the Department since March 2018. Prior to her appointment as Interim Chief Financial Officer, Ms. Santilli served as Assistant Chief Financial Officer and Controller of the Department from 2012 through February 2018 and previously held the role of Interim Chief Financial Officer of the Department from October 2010 through January 2012. Prior to her first service as Interim Chief Financial Officer, Ms. Santilli served as Chief Accounting Employee and Assistant Chief Financial Officer and Controller of the Department. She assumed the post as Controller in March 2008, as Assistant Chief Financial Officer in April 2008 and as Chief Accounting Employee in July 2010. Prior to being appointed as the Controller, Ms. Santilli was the Manager of Financial Reporting since 2003. Ms. Santilli has over 36 years of accounting and auditing experience. Ms. Santilli holds a bachelor's degree in business administration from California State University, Northridge and is a certified public accountant in the State and a certified internal auditor.

SIMON ZEWDU, *Senior Assistant General Manager of the Power System*. Mr. Zewdu assumed his current position as Senior Assistant General Manager of the Power System in October 2023 after serving as Interim Senior Assistant General Manager of the Power System since April 2023. Mr. Zewdu has over 24 years of experience with the Department and the City of Los Angeles, with duties spanning from substation design, project management, strategic planning, contracts, operations, and special projects. Prior to his current role, Mr. Zewdu led the Department's compliance with mandatory federal North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability standards including the Department's regulatory reporting obligations to State regulatory agencies. Mr. Zewdu also led the LA100 Equity Strategies Study in collaboration with the National Renewable Energy Laboratory (the "NREL") and UCLA. Over the years, Mr. Zewdu led the Department's transmission planning efforts to fulfill the Department's obligations as a transmission provider and managed the transmission engineering team responsible for the design of the Department's extra-high voltage overhead and underground transmission projects to support the reliability and resiliency of the Department's electric grid. Mr. Zewdu holds a bachelor's degree in electrical and computer engineering and a master's degree in business administration in finance.

KATHY M. FONG, *Assistant Chief Financial Officer and Controller*. Ms. Fong was named Assistant Chief Financial Officer and Controller of the Department in March 2020 after serving as the Acting Assistant Chief Financial Officer and Controller of the Department since March 2018. Ms. Fong previously served as Assistant Controller – Financial Reporting of the Department from August 2014 through February 2018 and held the role of Manager of Financial Reporting of the Department from June 2008 through July 2014. Prior to being appointed as the Manager of Financial Reporting in 2008, Ms. Fong served as the Assistant to the Manager of the Budget Office since 2002. Ms. Fong has over 34 years of accounting and budgeting experience. Ms. Fong holds a bachelor's degree in business administration with an option in accounting from California State University, Los Angeles and is a certified public accountant in the State and a certified management accountant.

PETER HUYNH, *Assistant Chief Financial Officer and Treasurer; Assistant Auditor*. Mr. Huynh was named Assistant Chief Financial Officer and Treasurer of the Department in October 2020 and Assistant Auditor of the Department in February 2021. Prior to his appointment as Assistant Chief Financial Officer and Treasurer, Mr. Huynh served as the Assistant Director of Finance and Risk Control Division of the Department since July 2006. He has over 34 years of financial management experience in debt management, risk control, financial planning, accounting, and auditing. Mr. Huynh holds a bachelor's degree in art and a certificate in accountancy from the California State University, Los Angeles. He also has a master's degree in business administration from Pepperdine University. Mr. Huynh is a certified public accountant in the State, a certified management accountant, and a chartered global management accountant.

Employees

As of January 31, 2024, the Department assigned approximately 5,234 Department employees to the Power System on a full time basis. Approximately 3,938 additional Department employees support both the Power System and the Water System on a shared basis.

The Department conducts personnel functions in accordance with the Charter-established civil service system (the "Civil Service System") applicable to most Department employees. In accordance with the Civil Service System, the Department makes appointments on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and 18 other management positions are specifically exempted from the Civil Service System.

The City Council approves the wages and salaries paid to all Department employees. In accordance with State law (the Meyers-Milias-Brown Act) and a conforming City ordinance (the Employee Relations Ordinance), the Department recognizes 14 bargaining units of Department employees. Five labor or professional organizations represent these employees' bargaining units. In the bargaining process the Department and the labor or professional organizations develop memoranda of understanding which set forth wages, hours, overtime and other terms and conditions of employment.

The International Brotherhood of Electrical Workers ("IBEW") represents more than 90% of the Department's employees through ten bargaining units. The Department's ten memoranda of understanding with IBEW have a term which commenced on October 1, 2022 and which expire on September 30, 2026.

The Department's memoranda of understanding with the Management Employees Association, Load Dispatchers Association, and Association of Confidential Employees, expire on December 31, 2025. The Department's memorandum of understanding with the Service Employees International Union, Security Unit, expired on September 30, 2022. The Department is currently in negotiations with the Service Employees International Union, Security Unit. All employment terms of the expired memorandum of understanding continue until a successor contract is executed. Since the advent of collective bargaining in 1974, work stoppages have been rare, occurring in 1974, 1981 and 1993.

Retirement and Other Benefits

Retirement, Retiree Medical, Disability and Death Benefit Insurance Plan. The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability, and Death Benefit Insurance Plan is a retirement system of employee benefits and includes the Water and Power Employees' Retirement Fund (the "Retirement Plan"), which is more fully described in "Note (13) Retirement Plan" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Retirement Plan are shared by the Power System and the Water System, with the Power System being responsible for approximately 67% of Retirement Plan costs. Since Fiscal Year 2014-15, the assumed rate of investment return on the Retirement Plan's assets has been incrementally decreased from 7.75% to 6.50%. Most recently, effective July 1, 2022, the Retirement Board lowered the assumed rate of return from 7.00% to 6.50%. A decrease in the assumed rate of return will generally contribute to an increase in the Department's required contributions to the Retirement Plan, including the Power System's share. The budgeted contributions for the Fiscal Year ending June 30, 2024 take into account this change in the discount rate. Investment return assumptions are determined through the Retirement Plan's Experience Study, which was most recently published on May 20, 2022.

As more fully described in Note 13(d), the Power System made contributions to the Retirement Plan of approximately $249 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $369 million), and the Power System made contributions to the Retirement Plan of approximately $218 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $325 million). For the Fiscal Year ending June 30, 2024, the Department has budgeted a contribution of approximately $304 million from the Power Revenue Fund to the Retirement Plan (as part of a total Department contribution of approximately $447 million).

The Department also has made, and will continue to make in the future, contributions to the Plan from the Water Revenue Fund.

The Department follows the provisions of Governmental Accounting Standards Board ("GASB") Statement No. 68, *Accounting and Financial Reporting for Pension – an amendment of GASB Statement No. 27* ("GASB No. 68"). GASB No. 68 requires employers with pension liabilities to disclose the net pension liability along with deferred inflows and outflows of resources related to the pension liability. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 68 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" of the Department's Power System Financial Statements. Specifically, see Note 6(f) for a discussion of the Power System's establishment of the regulatory asset discussed above.

According to the latest actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 22, 2023, as of July 1, 2023, the market value of the assets in the Retirement Plan was approximately $16.4 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $582.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $16.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $411.5 million. As of July 1, 2023, the Retirement Plan had unrecognized investment losses of approximately $171.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2023 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2023-24 would increase from approximately 31.4% of total Department covered payroll to 32.6% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2023 would decrease from approximately 97.6% to 96.6%.

According to the actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 23, 2022, as of July 1, 2022, the market value of the assets in the Retirement Plan was approximately $15.5 billion, which would result in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $616.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $15.8 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $318.0 million. As of July 1, 2022, the Retirement Plan had unrecognized investment losses of approximately $298.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2022 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2022-23 would increase from approximately 29.8% of total Department covered payroll to approximately 32.2% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2022 would decrease from approximately 98.0% to approximately 96.2%.

Contribution requirements for the Fiscal Year ending June 30, 2024 are set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities and future pension costs. However, the Retirement Plan uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retirement benefits, requires the employee to contribute a higher percentage of pay to the Retirement Plan, and ends the reciprocity agreement with the City's retirement plan. The Coalition of L.A. City Unions, whose members are not employed at the Department, has challenged the ending of the reciprocity agreement. The City is defending the challenge against the decision to end the reciprocity agreement. The outcome of the challenge to the end of the reciprocity agreement is not expected to have a material adverse impact on the Department or the Retirement Plan. According to a study of the proposed benefits of Tier 2, which was completed by The Segal Company on October 24, 2013, the estimated amount of contribution required to fund the benefit allocated to the current year of service (the "Normal Cost"), as a percentage of payroll, was 5.61% for Tier 2 (as compared to 16.35% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $877 million over 30 years (based on the 7.75% assumed rate of investment return on the Retirement Plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on September 22, 2023, the estimated contribution for Fiscal Year 2023-24 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, was 11.29% for Tier 2 (as compared to 21.12% for Tier 1). As of the July 1, 2023 actuarial valuation report, 53% of active Department members were covered under Tier 2.

Other Postemployment Benefits ("OPEB"). The Department provides certain healthcare benefits (the "Healthcare Benefits") and death benefits to active and retired employees and their dependents. These OPEB Benefits are more particularly described in "Note (14) Other Postemployment Benefits Plans" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Healthcare Benefits are shared by the Water System and the Power System, with the Power System historically being responsible for approximately 67% of the costs of the Healthcare Benefits. As more fully described in Note (14), the Power System paid Healthcare Benefits of approximately $75.9 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $113.2 million), and the Power System paid Healthcare Benefits of approximately $73.7 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $110.8 million). For the Fiscal Year ending June 30, 2024, the Department has budgeted approximately $78.3 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $118.7 million).

The Department also has paid, and will continue to pay in the future, Healthcare Benefits from the Water Revenue Fund, for the Water System's Healthcare Benefits costs.

According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, as of June 30, 2023, the market value of the assets of the Healthcare Benefits was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $345.8 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $371.7 million. As of June 30, 2023, the Healthcare Benefits had unrecognized investment gains of approximately $25.9 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2023, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 106.84% as of June 30, 2022 to 114.16% as of June 30, 2023. On a market value of assets basis, the funded ratio increased from 104.95% as of June 30, 2022 to 113.17% as of June 30, 2023. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $180.0 million as of June 30, 2022 to a surplus of $371.7 million as of June 30, 2023.

According to the actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 16, 2022, as of June 30, 2022, the market value of the assets of the Healthcare Benefits was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $130.3 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $180.0 million. As of June 30, 2022, the Healthcare Benefits had unrecognized investment gains of approximately $50.0 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2022, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 101.15% as of June 30, 2021 to 106.84%. On a market value of assets basis, the funded ratio decreased from 113.58% as of June 30, 2021 to 104.95% as of June 30, 2022. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $29.6 million as of June 30, 2021 to a surplus of $180.0 million as of June 30, 2022.

Contribution requirements for the Fiscal Year ending June 30, 2024 are set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities for Healthcare Benefits and future contribution requirements. However, the Healthcare Benefits uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

For a schedule that provides information about the Department's overall progress made in accumulating sufficient assets to pay Healthcare Benefits when due, prior to allocations to the Power System and the Water System, see the "Required Supplementary Information" of the Department's Power System Financial Statements.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retiree healthcare benefits. According to a study of the proposed OPEB for Tier 2 employees of the Department, which was completed by The Segal Company on November 8, 2013, the estimated Normal Cost, as a percentage of payroll, was 2.63% for Tier 2 (as compared to 4.33% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $136.5 million over 30 years (based on the 7.75% assumed rate of investment return on the OPEB plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, for Fiscal Year 2023-24, the Normal Cost, as a percentage of payroll, was estimated to be 4.36% for Tier 2 (as compared to 4.77% for Tier 1).

Effective July 1, 2017, the Department follows the provisions of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, an amendment of GASB Statement No. 45 ("GASB No. 75"). GASB No. 75 requires employers with other postemployment liabilities to disclose the net postemployment liability along with deferred inflows and outflows of resources related to the other postemployment liability. The Department adopted the provisions of GASB No. 75 beginning for the Fiscal Year ended June 30, 2018. Accordingly, the cumulative effect of the impact on net position as of July 1, 2017 was negative $661.2 million. As of June 30, 2023, the Power System had a net OPEB liability surplus of $11.8 million comprised of $87.4 million surplus of retiree medical and $75.6 million liability in death benefits. As of June 30, 2022, the Power System had a net OPEB liability surplus of $172.6 million comprised of $235.7 million surplus of retiree medical and $63.1 million liability in death benefits. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 75 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" in the Department's Power System Financial Statements. Specifically, see Note 6(g) for a discussion of the Power System's establishment of the regulatory asset discussed above.

Transfers to the City

Pursuant to the Charter, the City Council may, subject to the provisions of contractual obligations, direct a transfer of surplus money in the Power Revenue Fund to the City's reserve fund (a "Power Transfer") with the consent of the Board. The Board may withhold its consent if it finds that making the Power Transfer would have a material adverse impact on the Department's financial condition in the year the Power Transfer is to be made. In the event the Board does not approve any year's Power Transfer, the City Administrative Officer is to verify the Department's findings and make a report thereon and recommendations with respect thereto. After receiving such report, and in consultation with the City Council and the Mayor, the Board shall either amend or uphold its preliminary findings.

Pursuant to covenants contained in the Master Resolution, a Power Transfer may not exceed the net income of the prior Fiscal Year or reduce the Power System's surplus to less than 33-1/3% of total Power System indebtedness. Subject to the restrictions of the Charter and the Master Resolution, the Board has most recently approved transfers totaling $244,695,000 to the City during the Fiscal Year ending June 30, 2024. Such transfers are expected to be made in full prior to the end of Fiscal Year 2023-24.

The following table shows the amounts of the Power Transfer in each of the last five Fiscal Years:

POWER TRANSFERS
FOR FISCAL YEARS ENDED JUNE 30, 2019 – 2023
($ in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2019	$232,557
2020	229,913
2021	218,355
2022	225,015
2023	232,043

Source: Department of Water and Power of the City of Los Angeles.

The City does not include any funds in the Power Transfer that the Department collects pursuant to the Electric Rates established under the Incremental Electric Rate Ordinance, which was adopted in 2016. However, the Power Transfer includes surplus revenue generated from Electric Rates established under the Rate Ordinance adopted in 2008. Starting in Fiscal Year 2017-18, the Power Transfer is approximately 1.01 cents for every kWh sold to retail electric customers.

Insurance

The Department's insurance program currently consists of a combination of commercial insurance policies, a wildfire Catastrophe Bond ("CAT Bond") and self-insurance. All general liability claims within the Department's self-insured retention are administered under the Department's self-insurance program and the Department carries commercial excess general liability insurance above its self-insured retention. There are two separate towers of insurance. The first is for non-wildfire losses. After meeting the $3 million retention, the program has a primary layer of $35 million, which includes 50% of co-insurance for the 2024-25 policy year (April 2024 to April 2025). Co-insurance is a designated percentage of the policy that is retained by the Department and the remaining policy amount is recoverable from the insurer. Above the primary layer of $35 million are additional layers of commercial liability insurance that provide an additional $125 million of coverage, which has no co-insurance and would provide coverage up to the policy limits. The total limit available for non-wildfire losses is $160 million. There is a second tower of insurance that is solely for wildfire losses. The Department has a total of $50 million in self-insured retention that serves as its primary layer for wildfire coverage and above that primary self-insurance retention layer, the Department has procured an additional $115.5 million of commercial wildfire insurance, totaling an insurance tower of $165.5 million. To complement its overall wildfire insurance program, the Department has further provided for $31.5 million of wildfire coverage through a CAT Bond. The $31.5 million indemnity wildfire CAT Bond, which is for the three-year period September 2021 to September 2024, has an attachment point at $125 million and is intended to cover a portion of any large claim that might exceed the self-insurance and commercial insurance coverage. CAT Bonds are multi-year issuances and pay out based on a catastrophic fire event that occurs within the three-year period of the specific bond. CAT Bonds allow the Department to obtain additional wildfire coverage capacity outside of a commercial insurance policy, but, unlike commercial insurance, the Department achieves a premium cost that is fixed and known for the three-year period of the bond. Through the utilization of commercial insurance, the CAT Bond and self-insurance, the wildfire insurance program has a total limit of $197 million available for wildfire losses.

For discussion regarding liability issues as they relate to wildfire losses, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

Going forward, including following the expiration of the coverage period for the existing CAT Bond issuance, the Department will continue to consider any available coverage options in the market in order to ensure that the Department is adequately protected against catastrophic liability events and wildfires. In addition to the excess general liability insurance programs and the existing CAT Bond issuance, the Department continues to maintain a bona fide program of self-insurance as well. As of December 31, 2023, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $222.5 million in a restricted cash account. The Power Revenue self-insurance fund is specific to the Power Division and is primarily designed to cover a large catastrophic event that could affect the Power Division operations (*e.g.*, liability for a large wildfire). The Department annually reviews the amount retained for self-insurance and may adjust such amount if it deems such adjustment appropriate.

The Department has purchased a primary cyber insurance policy, with a self-insured retention component. This insurance policy covers certain types of cyber incidents and provides reimbursement coverage for costs to respond to data privacy or security incidents and for expenses incurred in connection with the investigation, prevention, and resolution of any cyber threat.

The Department commercially insures its physical plant through a policy of all risk property insurance, which is written on a replacement cost-basis. The policy covers all risk of physical loss or damage to buildings, structures, auxiliary and main plant equipment. Such insurance has a policy loss limit of $500 million for all claims in a single policy year. The all-risk property insurance has a deductible of $5 million. The Department has secured earthquake coverage and sudden and accidental pollution coverage as part of its all-risk property insurance program.

The Department's physical plant coverage does not provide coverage in certain events including terrorism or war. However, the Department has purchased a Terrorism Limits and Terrorism Risk Insurance Extension Act of 2005 ("TRIEA") Endorsement (the "Endorsement") to its excess general liability coverage under which coverage is extended to cover losses resulting from certain acts certified by the Secretary of the U.S. Department of the Treasury to be an act of terrorism, as defined in TRIEA. Currently, from 2002 through December 31, 2027, the Endorsement limits insurers liability for losses resulting from certified acts of terrorism when the amount of such losses exceeds $100 billion in any one calendar year. If the aggregate insured losses for all insurers exceed $100 billion, the Department's coverage may be reduced.

As a participant in the Palo Verde Nuclear Generating Station ("PVNGS") and associated transmission systems, the Department is an additional named insured on various forms of insurance providing protection against property and liability losses relating to such facilities. The amounts of coverage are established by participating owners and procured by the operating agent for the facility.

The Department, as the operating agent for the Intermountain Power Project ("IPP"), the Mead-Adelanto Transmission Project, the Pacific DC Intertie and in connection with its relationships with other entities and agencies, includes other entities or agencies as additional named insureds on the various forms of insurance procured for such facilities.

The Department continuously evaluates its insurance program and may modify the current configuration of commercial insurance and self-insurance with respect to the Power System. Insurance limits maintained by the Department are subject to change depending on market conditions and assessments by the Department as to risk exposure. The utilization of commercial insurance along with alternative risk options such as CAT Bonds allows the Department to strengthen its overall risk management program as well as provide flexibility in setting and adjusting its self-insurance retention limits as part of the continual review of the Department's insurance budget.

Investment Policy and Controls

Department's Trust Funds Investment Policy. The majority of the Power System funds are held in the Power Revenue Fund, investments of which are managed by the Office of Finance of the City. The funds have been invested as part of the City's investment pool program since 1983. Certain financial assets of the Department that are held in special-purpose trust or escrow funds with an independent trustee ("Trust Funds") more fully described in "Note (7) Cash, Cash Equivalents, and Investments" of the Department's Power System Financial Statements ("Note 7"), are not included in the City's investment pool program. The Department manages the investment of the Trust Funds in which approximately $694.5 million (investments at fair market value) was on deposit as of December 31, 2023. The Department's investment of such funds complies with the California Government Code in all material respects and such funds are invested according to the Department's Trust Funds Investment Policy (the "Trust Funds Investment Policy"), which sets forth investment objectives and constraints. For more information about the Trust Funds Investment Policy, see Note 7. Such funds consist of debt reduction trust funds, the nuclear decommissioning trust funds, the natural gas trust fund, the California Independent System Operating Markets trust fund, and the hazardous waste treatment storage and disposal trust fund. These trust funds are being held by U.S. Bank Trust Company, National Association as trustee/custodian. Amounts in the debt reduction trust fund are to be applied at the discretion of the Chief Financial Officer, to the retirement (including the payment of debt service, purchase, redemption and defeasance) of Power System debt, including obligations to Intermountain Power Agency ("IPA") and Southern California Public Power Authority ("SCPPA"). As of December 31, 2023, the debt reduction trust fund had a balance of approximately $505.8 million (investments at fair market value as of such date).

Under the Trust Funds Investment Policy, the Department's investment program seeks to accomplish three specific goals: (i) preserve the principal value of the funds, (ii) ensure that investments are consistent with each individual fund's liquidity needs and (iii) achieve the maximum yield/return on the investments.

The overall responsibility for managing the Department's investment program for the Trust Funds rests with the Department's Chief Financial Officer, who directs investment activities through the Department's Assistant Chief Financial Officer and Treasurer. An Investment Committee, comprised of the City Controller, a Board member designated by the Board President, the General Manager and the Department's Chief Financial Officer (the "Department Investment Committee") is charged with oversight responsibility. The Trust Funds Investment Policy is adopted by the Board from time to time, and fund activity is reviewed periodically by the Department Investment Committee to ensure its consistency with the overall objectives of the policy, as well as its relevance to current law and financial and economic trends.

The Department's Assistant Chief Financial Officer and Treasurer or its designee reviews all investment transactions for the Trust Funds on a monthly basis for control and compliance and submits quarterly investment reports that summarize investment income to the Department Investment Committee, the Board and the Mayor for information and evaluation.

POWER SYSTEM TRUST FUNDS INVESTMENTS
ASSETS AS OF DECEMBER 31, 2023
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Government Securities	$ 35,521
U. S. Sponsored Agency Issues	313,419
Supranationals	12,876
Medium term corporate notes	149,505
Municipal obligations	52,953
California state bonds	12,221
Other state bonds	39,130
Commercial paper	199
Certificates of deposit	40,225
Money market funds	38,415
Total	$694,464

Source: Department of Water and Power of the City of Los Angeles.
* Totals may not equal sum of parts due to rounding.

Department Financial Risk Management Policies. In order to manage certain financial and operational risk, the Board has adopted a number of policies in addition to its Trust Funds Investment Policy. The Board has adopted a Counterparty Evaluation Credit Policy designed to minimize the Department's credit risk with its counterparties. This policy applies to wholesale energy, transmission, physical natural gas and financial natural gas transactions entered into by the Department. Pursuant to this policy the Department assigns credit ratings to such counterparties. The policy requires the use of standardized netting agreements which require such counterparties to net positive and negative exposures to the Department and requires credit enhancement from counterparties that do not meet an acceptable level of risk. Sales to such counterparties are only permitted up to the amount of purchases with a netting agreement and, in certain cases, credit enhancement in place.

The Board has adopted a Retail Natural Gas Risk Management Policy designed to mitigate the Department's exposure to unexpected spikes in the price of natural gas used in the production of electricity to serve retail customers. This policy authorizes Department management to enter into transactions for natural gas subject to specified parameters, such as duration of contract and price and volumetric limits. It also establishes internal controls for natural gas risk management activity. See "THE POWER SYSTEM – Fuel Supply for Department-Owned Generating Units and Apex Power Project."

The Board has adopted a Wholesale Marketing Energy Risk Management Policy to establish a risk management program designed to manage the Department's exposure to risks resulting from purchases and sales of wholesale energy, transmission services and ancillary services. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types and establishes internal controls for wholesale energy risk management activity.

The Board has adopted an Environmental Credit and Renewable Energy Credit Policy to establish a risk management program that is designed to manage the Department's exposure to risks resulting from purchases and sales of emissions credits or allowances and other credits available for the purpose of compliance with environmental laws, rules, and regulations. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types, and establishes internal controls surrounding credit risk management activity.

The Board has adopted a Dodd-Frank Act Compliance Policy to ensure the Department complies with applicable provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and commodity futures trading commission requirements.

City Investment Policy. The Office of Finance of the City invests temporarily idle cash on behalf of the City, including that of the proprietary departments, such as the Department, as part of a pooled investment program. As of December 31, 2023, the Power System had approximately $1.58 billion of unrestricted cash and approximately $1.56 billion of restricted cash on deposit with the City. This month-end amount does not reflect the GASB Statement No. 31 fair market value adjustment. For information regarding the fair market value adjustment of the Department's pooled investment fund assets as of June 30, 2023, see Note 7(b) in the Department's Power System Financial Statements. This amount is in addition to what is on hand in the Trust Funds, see "– *Department's Trust Funds Investment Policy*" above. The City's pooled investment program combines general receipts with special funds for investment purposes and allocates interest earnings and losses on a pro-rata basis when the interest is earned and distributes interest receipts based on the previously established allocations. The primary responsibilities of the Office of Finance of the City and the pooled investment program are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. Funds invested by the Power System in the pooled investment program are available for withdrawal within five business days without penalties. In addition, 20% of the pool, as of June 30, 2023, had maturities less than one month and 39% of the pool, as of June 30, 2023, had maturities of one year or less.

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CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2023
(Dollars in Thousands)
(Unaudited)

	Amount	**Percent of Total**	**Power System Share**
U.S. Treasury Notes	$ 8,939,146	58.52%	$ 1,591,211
Commercial Paper	987,939	6.47	175,925
Medium-Term Notes	1,709,101	11.19	304,266
U.S. Agencies Securities	1,918,910	12.56	341,517
Supranationals	219,575	1.44	39,155
Short-Term Investment Funds	1,134,771	7.43	202,028
Asset-Backed Securities	305,709	2.00	54,382
Securities Lending Short-Term Repurchase Agreement	59,668	0.39	10,604
Negotiable Certificates of Deposit	0	0.00	0
Total General and Special Pools*	**$15,274,819**	**100.00%**	**$2,719,088**

Source: Department of Water and Power of the City of Los Angeles and Los Angeles City Treasurer.

Note: Department funds held by the City are both unrestricted and restricted funds. Totals may not equal sum of parts due to rounding.

Note: Fair Market Value as of June 30, 2023.

The City's investment operations are managed in compliance with the California Government Code and the City's statement of investment policy, which sets forth permitted investments, liquidity parameters and maximum maturity of investments. The investment policy is reviewed and approved by the City Council on an annual basis.

Monthly reports of investment activity are presented to the Mayor, the City Council and the Department to indicate, among other things, compliance with the investment policy. The City's Office of Finance does not invest in structured and range notes, securities that could result in zero interest accrual if held to maturity, variable rate, floating rate or inverse floating rate investments or mortgage-derived interest or principal-only strips.

The investment policy permits the City's Office of Finance to engage custodial banks to enter into short-term arrangements to lend securities to various brokers. Cash and/or securities (United States Treasuries and Federal Agencies only) collateralize these lending arrangements, the total value of which is required to be at least 102% of the market value of securities loaned out. The securities lending program is limited to a maximum of 20% of the market value of the City's Office of Finance's pool by the City's investment policy and the California Government Code.

For more information about the investments in the City's Office of Finance pool, see Note 7.

ELECTRIC RATES

Rate Setting

Pursuant to the Charter, the Board, subject to the approval of the City Council by ordinance (as discussed below), fixes the rates for electric service from the Power System ("Electric Rates"). The Charter provides that the Electric Rates shall be fixed by the Board from time to time as necessary. The Charter also provides that the Electric Rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied and the value of the service provided. The Charter further provides that rates for electric energy may be negotiated with individual customers, provided that such rates are established by binding contract, contribute to the financial stability of the Power System and are consistent with such procedures as the City Council may establish.

The Board is obligated under the Charter and the rate covenant in the Master Resolution to establish Electric Rates and collect charges in amounts which, together with other available funds, shall be sufficient to service the Department's Power System indebtedness and to meet the Power System's expenses of operation and maintenance. The Charter provides that Electric Rates are subject to the approval of the City Council by ordinance (a "Rate Ordinance"). The Charter further requires that the City Council approve Rate Ordinances for the Electric Rates prescribed in the rate covenant in the Charter, which rate covenant is also included in the Master Resolution.

The Department's completed interim rate review of the last rate action for Fiscal Year 2015-16 through Fiscal Year 2019-20 resulted in planned annual system average Electric Rate increase adjustments. The average yearly increase during the five-year period was approximately 4.5% for low-energy users, approximately 4.0% for midrange users, and approximately 5.5% for top tier users, reflected in increased actual pass-through cost adjustments and decreased Base Rate revenue targets.

The rate increase over these five Fiscal Years is reflected in the Incremental Electric Rate Ordinance and as a result, effective April 15, 2016, the Department's retail electric revenue requirement has been funded from the Rate Ordinance adopted in 2008 and the Incremental Electric Rate Ordinance through the following major components:

(a) Under the Rate Ordinance adopted in 2008:

(i) Base Rates: Base Rates are used to fund expenditures including debt service arising from capital projects (except projects relating to the Renewable Portfolio Standard ("RPS")), operational and maintenance expenses (except as RPS-related), public benefit spending, property tax, and a prorated portion of the Power Transfer;

(ii) Reliability Cost Adjustment (the "RCA"): The RCA is used to recover certain power reliability expenditures; and

(iii) Energy Cost Adjustment (the "ECA"): The ECA is used to recover expenditures for fuel, non-renewable purchased power, RPS and energy efficiency-related expenditures.

(b) Under the Incremental Electric Rate Ordinance:

(i) Incremental Base Rates: The Incremental Base Rates are used to recover costs of providing electric utility service that are not recovered by Base Rates or any of the Rate Ordinance cost adjustments, including labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly-owned plants and other inflation-sensitive costs, in addition to including the Power Access Charge, which is a consumption-based tiered charge applied to residential non-Time-of-Use Residential Rate customers used to recover basic infrastructure costs for providing access to the power grid;

(ii) Incremental Reliability Cost Adjustment (the "IRCA"): The IRCA is used to recover costs associated with operations and maintenance, debt service expense of the Power System Reliability Program and RCA under-collection;

(iii) Variable Energy Adjustment (the "VEA"): The VEA is used to recover costs associated with fuel, non-renewable portfolio standard power purchase agreements, economy purchases, legacy ECA under-collection and Base Rates decoupling from energy efficiency impact;

(iv) Capped Renewable Portfolio Standard Energy Adjustment (the "CRPSEA"): The CRPSEA is used to recover costs associated with RPS operations and maintenance, debt service and energy efficiency programs; and

(v) Variable Renewable Portfolio Standard Energy Adjustment (the "VRPSEA"): The VRPSEA is used to recover costs associated with RPS market purchases and costs above any operations and maintenance and debt service payments.

The RCA, ECA, IRCA, VEA, CRPSEA and VRPSEA are pass-through cost adjustments applied by factors that the Department may change with approval of the Board, without changes to existing Rate Ordinances.

Recent Rate Actions. On the recommendation of the Office of Public Accountability (the "OPA"), the Board decreased the Base Rate revenue targets for Fiscal Year 2018-19 and Fiscal Year 2019-20 by 2% each. The OPA further recommended, and the Department supports the recommendation, to use four-year rate action cycles, rather than replicate the recent five-year rate action cycle. In June 2022, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2022-23 of 2.035%, in accordance with the provisions of the Incremental Electric Rate Ordinance. In June 2023, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2023-24 of 5.60% in accordance with the provisions of the Incremental Electric Rate Ordinance. The increase to the Base Rate revenue target will continue to provide the Department with sufficient revenues to meet the rate covenant under the Master Resolution and the Board adopted financial metrics. The Department is in the process of reviewing the Rate Ordinance and Incremental Electric Rate Ordinance and, based on current and assumed market conditions, determining what changes, if any, need to be made in connection with the next rate action. Department staff expects to propose a schedule for the next rate action to the Board in the second half of calendar year 2024.

Proposition 26. In 2010, California voters approved Proposition 26 ("Proposition 26"), an initiative measure amending Article XIII C of the State Constitution to add a new definition of "tax." Each such tax cannot be imposed, extended, or increased by a local government without voter approval. Article XIII C of the State Constitution, as amended by Proposition 26, defines "tax" to include any levy, charge, or exaction imposed by a local government, except, among other things, (a) charges imposed for benefits conferred, privileges granted, or services or products provided, to the payor (and not to those not charged) that do not exceed the reasonable costs to the local government of conferring, granting or providing such benefit, privilege, service, or product, and (b) property-related fees imposed in accordance with the provisions of Article XIII D of the State Constitution. The Department believes that the Electric Rates and charges do not constitute taxes as defined in Article XIII C of the State Constitution.

A voter initiative entitled "The Taxpayer Protection and Government Accountability Act" ("Initiative 1935") has been determined to be eligible for the November 2024 Statewide general election and, unless withdrawn by its proponent prior to June 27, 2024, or removed pursuant to the emergency petition for writ of mandate filed by the Governor of California with the California Supreme Court seeking such removal, will be certified as qualified for the ballot in such election. Were it to be adopted by the voters in the Statewide general election, Initiative 1935 would amend the California Constitution to, among other things, provide that charges for services or products provided directly to the payor (such as charges for electricity) are "taxes" subject to voter approval unless the local government can prove by clear and convincing evidence that the charge is reasonable and does not exceed the "actual cost" of providing the service or product, defined as "(i) the minimum amount necessary to reimburse the government for the cost of providing the service or the product to the payor, and (ii) where the amount charged is not used by the government for any purpose other than reimbursing that cost." If adopted, Initiative 1935 would be subject to judicial interpretation. The Department is unable to predict whether and how Initiative 1935, if adopted, would be interpreted by the courts, and there can be no assurance that any such interpretation or application would not have an adverse impact on the Department, the Power System or the revenues of the Power System.

Board Adopted Financial Planning Criteria. The Board has directed the Department to use the following criteria when preparing the Power System's financial plans with respect to Electric Rates: (i) maintain a minimum operating cash target of the equivalent of 170 days of operating expenses, (ii) maintain full obligation coverage of at least 1.7 times, and (iii) maintain a debt-to-capitalization ratio of less than 68%. These criteria are subject to reviews and adjustments from time to time by the Board with advice from the Department's financial advisors and were most recently revised on May 26, 2020.

Neighborhood Councils. Pursuant to a Memorandum of Understanding with the City's Neighborhood Councils, the Department agrees to use its best efforts to undertake a 60-day or 90-day notification and outreach period (depending on the duration of the Department's proposed rate action) prior to submitting a residential or non-residential retail business customer electric rate increase proposal involving changes to the Rate Ordinances to the Board for approval. The Neighborhood Councils have indicated they will use their best efforts to provide written input regarding such rate proposals to the Department within 60 days of receiving the above-discussed notifications.

Office of Public Accountability. Section 683 of the Charter establishes the OPA with respect to the Department. The primary role of the OPA is providing public, independent analysis to the Board and City Council about Department actions as they relate to the Electric Rates and water rates. The role of the OPA is advisory rather than as an approver of Electric Rates. The OPA is headed by an Executive Director appointed by a citizens committee, subject to confirmation by the City Council and Mayor. The Executive Director of the OPA serves as the Ratepayer Advocate for the OPA. On February 1, 2012, Dr. Frederick H. Pickel was appointed as Executive Director of the OPA (the "Ratepayer Advocate"); and on December 5, 2018, Dr. Pickel was reappointed as the Ratepayer Advocate for a five-year term. Dr. Pickel's term as Executive Director of OPA and Ratepayer Advocate expired on December 5, 2023, however, Dr. Pickel will continue to serve in those roles until his retirement, which is expected to occur in the second quarter of 2024. The rate action effective April 15, 2016 was supported by the Ratepayer Advocate following his review of the proposed rate changes. The rate action included certain changes proposed by the Ratepayer Advocate. As a result of the rate action involving the Incremental Electric Rate Ordinance for Fiscal Year 2015-16 through Fiscal Year 2019-20, the Department is required to provide semi-annual written reports each year regarding certain Board-established metrics to the Board and the OPA.

Rate Regulation

While changes in the retail Electric Rate ordinances are subject to approval by the City Council, the authority of the Board to impose and collect retail Electric Rates for service from the Power System is not subject to the general regulatory jurisdiction of the California Public Utilities Commission (the "CPUC") or any other State or federal agency. The California Public Utilities Code (the "Public Utilities Code") contains certain provisions affecting all municipal utilities such as the Power System. At this time, neither the CPUC nor any other regulatory authority of the State nor the Federal Energy Regulatory Commission ("FERC") approves the Department's retail Electric Rates. It is possible that future legislative and/or regulatory changes could subject the Department to the jurisdiction of the CPUC or to other limitations or requirements.

The California Energy Resources Conservation and Development Commission, commonly referred to as the California Energy Commission (the "CEC"), is authorized to evaluate rate policies for electric energy as related to the goals of the Warren-Alquist State Energy Resources Conservation and Development Act (Public Resources Code Section 25000 et seq.) and make recommendations to the Governor of the State, the Legislature and publicly-owned electric utilities ("POUs") such as the Department.

Although its retail Electric Rates are not subject to approval by any state or federal agency, the Department is subject to certain provisions of the Public Utilities Code and the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA applies to the purchase of the output of "qualified facilities" ("QFs") at prices determined in accordance with PURPA. The Energy Policy Act of 2005 repealed the mandatory purchase obligation for electric utilities when FERC determines that the QFs have non-discriminatory access to wholesale power markets with certain characteristics. The Department has neither applied for nor been relieved of its mandatory purchase obligation. The Department believes that it is currently operating in compliance with PURPA.

Under federal law, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise), including the Department, to provide electric transmission access to others at cost-based rates. FERC also has licensing authority over hydroelectric facilities and regulates the reliability and security of the nation's bulk power system.

With, among other things, the consent of the Department, operational control of the transmission facilities owned or controlled by the Department may be transferred to the California statewide network administered by the California Independent System Operator Corporation ("Cal ISO"). See "THE POWER SYSTEM – Transmission and Distribution Facilities." In 2017, the Department updated its Open Access Transmission Tariff ("OATT"), which included revising the cost-of-service and rate design for the Department's wholesale transmission rates. In 2020, the Department updated its OATT to facilitate entry into Cal ISO's Western Energy Imbalance Market (the "EIM"). The April 2020 amendment to the Department's OATT focused predominantly on non-rate terms and conditions related to the EIM, to ensure that services under the OATT would continue to be provided in a comparable and not unduly discriminatory or preferential manner to all of the Department's OATT customers. The April 2020 amendment largely followed similar, prior OATT amendments of other utilities already participating in the EIM. A further minor non-rate terms and conditions amendment occurred in December 2021. For more information on the Department's entry into the Western EIM, see "THE POWER SYSTEM – Transmission and Distribution Facilities."

Billing and Collections

General. With some limited exceptions, the Department currently bills residential customers on a bimonthly basis and commercial and industrial customers on a monthly basis. The Department prepares bills covering water and electric charges and non-Department charges (such as sewer services, solid waste resources fee and State and local taxes). Payments are posted in the following order: overdue receivables, customer deposits, water charges, electric charges, State and local taxes, sewer service charges, solid waste resources fees and bulky item fees. Within overdue receivables, payments received are applied in the same order for which payments are posted for current receivables.

In September 2022, the Department launched a new Level Pay system that provides eligible residential customers the opportunity to pay a monthly recurring amount for utility services based on an average of the customer's past usage and costs over the previous 12 months. Payment terms of 12, 24 and 36 months are available. At the end of the payment term, Level Pay will automatically renew and the monthly amount will be recalculated. Any underpayment or overpayment will be rolled into the calculation of the next term. The customer may cancel Level Pay at any time. It is not known at this time how many customers will ultimately sign up for Level Pay. Participation to date has been minimal but is continuing to increase. The Department does not anticipate Level Pay to have a materially adverse impact on its finances or operations.

Billing System. In September 2013, the Department launched a new customer information and billing system, designed and implemented by Pricewaterhouse Coopers LLP. Immediately following the launch of the new billing system, the Department experienced numerous billing issues in connection with the new system, including, but not limited to, (a) the inability to issue bills to customers, (b) the inability to issue accurate bills to customers, (c) an increase in estimated bills that were sent to customers where metering information was not available, and (d) the inability to generate multiple business reports, including financial reports reflecting the Department's accounts receivable. The customer information and billing system is currently being used by the Department. The Department continues to work to improve the functionality of the system to meet the Department's original expectations for the system.

Delinquencies. Based on annual historical experience of delinquencies, the Department historically has been unable to collect approximately 0.7% of the amounts billed to its customers. In light of the prior billing issues noted above and in response to the COVID-19 pandemic described below, the allowance for doubtful accounts has been increased to 2.0% of Power System sales since Fiscal Year 2020-21, creating an allowance of $280.4 million for the Fiscal Year ended June 30, 2023. The Power System's accounts receivable (including utility user's tax) as of June 30, 2023 were $1.05 billion compared to $855.7 million as of June 30, 2022. Of these amounts, $608.6 million (58.05% of total receivables) and $445.2 million (52.03% of total receivables) were 120 days or more past the payment due date as of June 30, 2023 and June 30, 2022, respectively. As of December 31, 2023, the Power System's allowance for doubtful accounts was $289.9 million and accounts receivable were $1.26 billion (including utility user's tax). Of these amounts, $734.1 million (58.36% of total receivables) were 120 days or more past the payment due date. As of December 31, 2022, the Power System's allowance for doubtful accounts was $309.7 million and accounts receivable were $1.1 billion (including utility user's tax). Of these amounts, $518.4 million (48.79% of total receivables) were 120 days or more past the payment due date.

COVID-19 Effects. In response to the COVID-19 pandemic, the Department deferred disconnection of water and power services to customers who were unable to pay their bills due to financial hardship, which deferrals officially ended on March 31, 2022 (the Department began the resumption of disconnections for commercial customers in June 2023 and is currently working on a plan to resume service disconnections for residential customers in the near future). As a result of the deferral of disconnections, the Department has experienced an increase in the amount of bills that are 120 days or more past their payment due date as described above under "Delinquencies." Ultimately, customers are still responsible to pay the billed amounts and the Department will work with customers by providing payment options. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Global Health Emergencies; COVID-19 Pandemic."

The California Legislature established the 2021 California Arrearage Payment Program ("2021 CAPP") to provide financial assistance for California energy utility customers to help reduce past due energy bill balances during the COVID-19 pandemic. Administered by the Department of Community Services and Development (the "CSD"), the 2021 CAPP dedicated approximately $994 million in federal American Rescue Plan Act funding to address Californian's energy debts, of which approximately $299 million was allocated for financial assistance to customers of POUs and electrical cooperatives. The 2021 CAPP implementation was divided into four distinct phases. During phase one, the total residential energy arrearages were quantified through a survey of energy utilities. During phase two, applications were submitted for assistance. During phase three, 2021 CAPP benefits were applied directly to eligible residential and commercial customer accounts. During phase four, required reports were submitted to the CSD to confirm the outcome of delivered 2021 CAPP benefits. The Department submitted its survey on September 3, 2021 including a funding request of approximately $203 million for residential arrearages and approximately $109 million for commercial arrearages. The Department received $202.8 million of funding of which $201.5 million have been credited towards residential arrearages. As authorized by the CSD, the Department distributed the remaining $1.3 million towards residential and commercial arrearages in March 2022.

The California Legislature established the 2022 California Arrearage Payment Program, which dedicates approximately $1.2 billion to address Californian's energy debts. The Department submitted its survey on October 19, 2022 including a funding request of approximately $76.6 million for residential arrearages. The Department received the requested funding amount and credited residential arrearages in January 2023.

Write-Off Procedures. Uncollectible accounts are recoverable by the Department by passing on such "bad debts" to the ratepayers via pass-through adjustment factors. Due to hot weather in the summer and associated higher bills and the Department's bimonthly billing process, accounts receivable balances generally increase in the late summer and autumn and generally decrease in the winter and spring. These accounts receivable balances include inactive accounts. Inactive accounts that are included in accounts receivable that cannot be linked to an active account will be written off as uncollectible.

Customer Bill of Rights. In January 2017, the Board adopted a "Customer Bill of Rights" which was developed by the Department in consultation with then Mayor Eric Garcetti and is designed to improve service for Department customers. On February 26, 2019, the Board extended the "Customer Bill of Rights" indefinitely.

THE POWER SYSTEM

General

The Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,730 megawatts ("MW") and net dependable capacity of 8,015 MW as of December 31, 2023, and properties with a net book value of approximately $13.7 billion as of December 31, 2023. The Power System's highest load registered 6,502 MW on August 31, 2017. Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department achieved its energy efficiency goal of 15% energy efficiency savings by 2020 and is now focused on a tentative projection towards an additional 3,431 gigawatt hours ("GWhs") of energy savings by 2035. For the operating statistics of the Power System, see "OPERATING AND FINANCIAL INFORMATION – Summary of Operations."

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The Department estimated that the Power System's capacity (as of December 31, 2023) and energy mix (actual numbers for calendar year 2022) were approximately as follows:

DEPARTMENT GENERATION MIX PERCENTAGES

Resource Type	Capacity Percentage[(1)]	Energy Percentage[(2)]
Natural Gas	36%	34.5%
Large Hydro	16	4.0
Coal	11	12.6
Nuclear	4	13.3
Renewables	33	35.6
Storage	<1	–
Unspecified Sources of Energy[(3)]	–	–
Total	100%	100%

(1) Net Maximum Unit Capability as of December 31, 2023.
(2) Energy percentage is based on the Department's calendar year 2022 fuel mix submission as part of the 2022 Annual Power Content Label (APCL) to the California Energy Commission in September 2023.
(3) Unspecified sources of energy means electricity from transactions that are not traceable to specific generation sources.
Note: Totals may not equal sum of parts due to rounding.

The Department anticipates that its generation mix will change in response to statutory and regulatory developments. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY."

Generation and Power Supply

The Power System has a number of generating resources available to it. The following discussion describes the Department's solely owned, jointly owned and contracted generation facilities, as well as fuel and water supplies and spot purchase activities. Currently, the Department's base load requirements are fulfilled primarily by generating capacity at IPP and PVNGS, and balanced with its natural gas, hydroelectric, renewable resources and spot purchases. The following information concerning the capacities of various facilities is as of December 31, 2023.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of December 31, 2023, are summarized in the following table:

DEPARTMENT OWNED FACILITIES

Type of Fuel	Number of Facilities	Number of Units	Net Maximum Capacity (MW)(1)	Net Dependable Capacity (MW)(1)
Natural Gas	4(2)	29(2)	3,373	3,202
Large Hydro	1	7	1,265	1,265
Renewables	66	163(3)	417	277(4)
Storage	1	1	20	20
Subtotal	**72**	**200**	**5,075**	**4,764**
Less: Payable to the California Department of Water Resources	–	–	(120)(5)	(40)(5)
Total	**72**	**200**	**4,955**	**4,724**

Source: Department of Water and Power of the City of Los Angeles.

(1) Based on 2022 capacity ratings.

(2) Consists of the four Los Angeles Basin Stations (Haynes, Valley, Harbor and Scattergood) discussed and defined below. See "*– Once-Through-Cooling Units Phase-Out"* below for information regarding the future expected phase out of certain natural gas units.

(3) Includes 22 of the hydro units at the Los Angeles Aqueduct, Owens Valley and Owens Gorge hydro units that are certified as renewable resources by the CEC. Also included are Department-built photovoltaic solar installations, the Pine Tree Wind Project and a local small hydro plant. Not included are the units that were upgraded at the Castaic Plant.

(4) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

(5) Energy payable to the California Department of Water Resources for energy generated at the Castaic Plant. This amount varies weekly up to a maximum of 120 MW.

Los Angeles Basin Stations. The Department is the sole owner and operator of four electric generating stations in the Los Angeles Basin (the "Los Angeles Basin Stations"), with a combined net maximum generating capacity of 3,373 MW and a combined net dependable generating capacity of 3,211 MW. Natural gas is used as fuel for the Los Angeles Basin Stations. Ultra-low-sulfur distillate is used for emergency back-up fuel. See "– Fuel Supply for Department-Owned Generating Units and Apex Power Project." See also "– Projected Capital Improvements." The four Los Angeles Basin Stations are briefly described below.

Haynes Generating Station. The largest of the Los Angeles Basin Stations is the Haynes Generating Station, located in the City of Long Beach, California. The Haynes Generating Station currently consists of eleven generating units with a combined net maximum capacity of 1,614 MW and a net dependable capacity of 1,512 MW. Originally comprising six units, two of the original units were repowered in 2005 and replaced with a combined-cycle generating unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two–plus–one configuration (and are counted by the Department as three generating units). In 2013, the Department completed the replacement of an additional two of the original units with six advanced simple-cycle gas turbine units. In 2022, the Department completed the demolition of the four Haynes Generating Station Units that were decommissioned to create a construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Valley Generating Station. The Valley Generating Station is located in the San Fernando Valley and is currently comprised of a simple-cycle generating turbine unit and a combined-cycle generating unit, which consists of two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). The net maximum plant capacity for the Valley Generating Station is 555 MW. The total net dependable capacity for the Valley Generating Station is 532 MW. The Department expects to demolish four Valley Generating Station Units that were decommissioned in 2002 to create a construction area for a future energy project. The demolition of the decommissioned Valley Generating Station Units is not expected to impact the energy output of the Valley Generating Station. Demolition is expected to be completed by November 2026.

Valley Generating Station Gas Vent-Off. While conducting methane surveys across the State for the CEC in August 2020, the Jet Propulsion Laboratory observed an increase of methane vent-off over the Valley Generating Station reciprocating natural gas compressor area. The Department installed new design rod packing seals in December 2020 that have been working as designed.

Five Los Angeles Superior Court cases were filed related to the referenced vent-off at the Valley Generating Station. The most significant of the cases, a class action lawsuit with a putative class of 30,000 individuals, was dismissed in December 2021. Additionally, punitive damages were removed, and the number of causes of action was reduced. Those court actions significantly eliminate the financial recovery expected by plaintiffs' counsel. With the dismissal of the class action lawsuit, there are four remaining cases, including *Pueblo y Salud, Inc, et. al. v. Los Angeles Department of Water and Power, et al.*, 21STCV04346, the lead case. The remaining cases have an aggregate of approximately 2,500 individual plaintiffs represented by various counsel. All pending cases have been deemed related by the court and are assigned to the same judge in the Los Angeles Superior Court.

The Department's exposure for the Valley Generation Station, if there is liability, is not now known. The Department has notified insurance carriers which may afford possible coverage for the underlying incident(s), however, at the present time no insurance coverage nor the amount of coverage, if any, has been confirmed.

Harbor Generating Station. The Harbor Generating Station is located in Wilmington, California. The Harbor Generating Station is comprised of eight generating units, including five simple-cycle generating turbine units and a combined-cycle unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). Harbor Generating Station's net maximum capacity is 426 MW with a net dependable capacity of 425 MW. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process– State Water Resources Control Board*" and "*– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Scattergood Generating Station. The Scattergood Generating Station is located in Playa Del Rey, California and is currently comprised of two conventional steam boiler generating units, one combined-cycle unit, which consists of two generating units in a one-plus-one configuration, and two advanced simple-cycle gas turbines, for a total of six generating units, with a net maximum capacity of 778 MW and a net dependable capacity of 742 MW from natural gas. An original unit of the Scattergood Generating Station was decommissioned in 2015 and has been demolished to create the construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures.

Once-Through-Cooling Units Phase-Out. Generating units at the Los Angeles Basin Stations that currently utilize once-through-cooling have a total generation nameplate of 1,661 MW, and a net maximum capacity of 1,486 MW. In February 2019, then Mayor Eric Garcetti announced that these units would be phased out and replaced with energy storage and clean energy alternative assets. The Department has initiated the City's planning efforts for replacing the capacity of the once-through cooling units as they retire by December 31, 2029. As part of these planning efforts, the Department issued a distributed energy resources request for proposals ("DER RFP") in September 2020 to explore the potential of in-basin distributed energy resources. Meanwhile the CEC launched its Demand Side Grid Support ("DSGS") Program in Summer 2022, which closely resembles the Department's DER RFP. As the result, in late 2022 the Department started pursuing the CEC sponsored DSGS Program, which is funded by tax payers instead. The Department expects to launch the DSGS Program in 2024. In addition, the Department presented a 2022 Power Strategic Long-Term Resource Plan (the "2022 Strategic Long-Term Resource Plan") to the Board in September 2022, which details high level initiatives to address once-through cooling units' phase-out and align with LA100 Study scenarios, and to formalize a roadmap for achieving 100% carbon free energy by 2035. The 2022 Strategic Long-Term Resource Plan was finalized and released in July 2023. See also "–Renewable Power Initiatives – L.A.'s Green New Deal."

Other Department-Owned Generating Facilities. In addition to the Los Angeles Basin Stations, the Department is the sole owner of a number of other generating facilities. Certain of the Department's hydroelectric projects are described below. See also "–Renewable Power Initiatives."

Castaic Pump Storage Power Plant. The Castaic Pump Storage Power Plant is located near Castaic, California (the "Castaic Plant") just before the terminus of the west branch of the California Aqueduct at Castaic Lake. The Castaic Plant is the Department's largest source of hydroelectric capacity and consists of seven units. The Castaic Plant's net maximum capacity and net dependable capacity for the seven units is 1,265 MW. The seven units completed a modernization process in August 2016. A FERC license pursuant to which the Department operates the Castaic Plant expired in 2022. The Department, in partnership with the California Department of Water Resources (the "CDWR"), is in the process of renewing this FERC license. FERC has not yet issued a new license. Under federal regulations, FERC issued an annual license on February 3, 2022, for the continued operations of Castaic Power Plant under the current license conditions. This annual license will be automatically renewed until FERC issues a new license. The Castaic Plant provides peaking and reserve capacity and is normally not a source of energy to the Department's net base load requirements. The Castaic Plant obtains water supply via the water conveyance system (the "State Water Project") operated by the CDWR, which has frequently been the subject of litigation that generally alleges that the CDWR is illegally "taking" listed species of fish through operation of the State Water Project export facilities and that the CDWR should cease operation of the State Water Project pumps. The CDWR has altered the operations of the State Water Project to accommodate certain listed species, which has had the effect of reduced pumping from the affected waters. Future litigation of this nature could influence how the State Water Project is operated and further reduce water flow to the Castaic Plant. The Department cannot predict at this time what effect this type of litigation will have on the Power System. See "– Water Supply for Department-Owned Generating Units" below.

Owens Gorge and Owens Valley Hydroelectric Generation. The three Owens Gorge and seven Owens Valley hydroelectric generating units (the "Owens Gorge and Owens Valley Hydroelectric Generation") are located along the Owens Valley in the Eastern High Sierra region of the State. The aggregate net dependable capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 52 MW and the net maximum capacity totals 122 MW.

The Owens Gorge and Owens Valley Hydroelectric Generation is a network of hydroelectric plants which use water resources of the Los Angeles Aqueduct and three creeks along the Eastern Sierras. The water flow fluctuates from year to year and as a result water flow may be reduced from seasonal norms from time to time. Since 1995, the total aqueduct exports from Owens Valley to the City have gone from approximately 476,000 acre-feet per year to currently approximately 252,000 acre-feet per year (based on the 30-year median). This difference is due to environmental uses in the Owens Valley, including Mono Lake level restoration, Lower Owens River restoration, reduced groundwater pumping and Owens Lake dust mitigation. Consequently, this water use reallocation has resulted in a reduction of downstream hydroelectric generation, which is accounted for in the annual updates of the Power System's resource plan; however, efforts are underway to reduce the amount of water required for Owens Lake dust mitigation. An estimated reduction of up to 10,000 acre-feet may be achieved depending upon terms agreed upon with applicable regulatory authorities, and may result in increased aqueduct exports from Owens Valley to the City.

San Francisquito Canyon and the Los Angeles and Franklin Reservoirs. The Department also owns and operates twelve hydroelectric units located north of the City along the Los Angeles Aqueduct in San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs. The net aggregate dependable plant capacity of these smaller units is 42 MW and the net maximum capacity totals 78 MW.

Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units

The Department has additional generating resources available as capacity rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Also, the Department benefits from distributed generation ("DG") capacity connected to the Department's grid from customer solar photovoltaic installations through net metering and customer generation rates and from other DG units through a Feed-in-Tariff. These interests, as of December 31, 2023, are summarized in the following chart and discussed below. Each project participant with respect to jointly-owned units is generally responsible for providing its share of construction, capital, operating, decommissioning, and maintenance costs.

JOINTLY-OWNED GENERATING UNITS AND
CONTRACTED CAPACITY RIGHTS IN GENERATING UNITS

Type	**Number of Facilities**	**Department's Net Maximum Connected Capacity (MW)**	**Department's Net Dependable Connected Capacity (MW)**
Coal	1	1,202[(1)]	1,202
Natural Gas	1	578	483
Large Hydro	1	496[(2)]	268[(2)]
Nuclear	1	387[(3)]	380
Renewables/Distributed Generation	81,110[(4)]	3,112	958[(5)]
Total	**81,114**	**5,775**	**3,291**

Source: Department of Water and Power of the City of Los Angeles.

(1) The Department's IPP entitlement is 48.62% of the maximum net plant capacity of 1,800 MW. An additional 18.17% portion of the IPP entitlement is subject to variable recall as set forth under "*Intermountain Power Project – Power Recalls*" below.

(2) The Department's Hoover Power Plant contract entitlement is 496 MW, which is 23.90% of the Hoover total contingent capacity and 14.7% of the firm energy. Hoover Power Plant output constantly varies due to low water levels at Lake Mead resulting from drought conditions.

(3) The Department's PVNGS entitlement is 9.66% of the maximum net plant capacity of 4,003 MW. See "*– Palo Verde Nuclear Generating Station*" below.

(4) The Department's contract renewable resources in-service include a hydro unit in the Los Angeles area, wind farms in Oregon, Washington, Utah and Wyoming, and customer solar photovoltaic installations and other DG units located in the Los Angeles region.

(5) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

Intermountain Power Project.

General. The IPP consists of: (i) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Delta, in Millard County, Utah; (ii) a +500 kilovolts ("kV"), direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System") (see "– Transmission and Distribution Facilities – *Southern Transmission System*"); (iii) two 50-mile, 345 kV, alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144-mile, 230 kV, alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"); (iv) a microwave communications system; (v) a railcar service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station"). Pursuant to a Construction Management and Operating Agreement between IPA and the Department, IPA appointed the Department as project manager and operating agent responsible for, among other things, administrating, operating and maintaining the IPP.

Power Contracts. Pursuant to a Power Sales Contract with IPA (the "IPP Contract"), the Department is entitled to 48.617% of the capacity of the IPP (currently equal to 875 MW). The term of the IPP Contract ends on June 15, 2027.

Pursuant to the IPP Contract, the Department is required to pay in proportion to its entitlement share the costs of producing and delivering electricity as a cost of purchased capacity. The Department also has available additional capacity in the IPP through an excess power sales agreement with certain other IPP participants (the "IPP Excess Power Sales Agreement"). Under the IPP Excess Power Sales Agreement the Department is entitled to an additional 18.168% of the capacity of IPP (currently equal to approximately 327 MW), subject to recall as described below. The IPP Contract requires the Department to pay for such capacity and energy on a "take-or-pay" basis as operating expenses of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

In Fiscal Year 2022-23, the IPP operated at a plant net capacity factor of 37.8% and provided approximately 5.9 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes approximately 3.9 million MWhs to the Power System.

Intermountain Generating Station upon the termination of the IPP Contract. In order to facilitate the continued participation of the Department and other power purchasers in the IPP beyond the IPP Contract's termination in 2027, the IPA Board issued the Second Amendatory Power Sales Contract which amended the IPP Contract to allow for the repowering of the plant to replace the coal units with combined cycle natural gas units by July 1, 2025 that would allow for compliance with greenhouse gas ("GHG") emissions performance standards. Pursuant to the provisions of the power sales contracts, the IPP participants also agreed to reduce the initially planned generation capacity of the repowered plant from 1,200 MW to 840 MW. IPA released a request for proposals in June 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with green hydrogen fuel (*i.e.*, hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% green hydrogen starting in 2025 and the subsequent goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. The request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was executed in early 2022 securing energy conversion and storage services. This contract will provide the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units in 2025. It is estimated that the repowering of the plant to the new combined cycle units at IPP will cost approximately $1.7 billion. This estimate does not include the hydrogen facilities being constructed. Upgrades to the Switchyard and replacement of converter stations are also being undertaken at an estimated cost of approximately $2.7 billion, reflecting a change in scope requested by the Department and the cities of Burbank and Glendale to upgrade portions of the converter station to 3,000 MW. SCPPA has issued bonds to finance a portion of the costs of the upgrades to the Switchyard and converter station replacements. See "– Transmission and Distribution Facilities – *Southern Transmission System.*" See also "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

The original power sales contracts, including the IPP Contract, will terminate on June 15, 2027, at which point the IPP Renewal Power Sales Contracts (which were executed in 2017) will immediately take operational effect and continue for a term ending in 2077. Most of the power purchasers under the original power sales contracts will continue to be IPP participants under the IPP Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the IPP Renewal Power Sales Contracts.

The city of Burbank will take a smaller share of generation capacity under the IPP Renewal Power Sales Contracts, and the Department and the city of Glendale both increased their respective generation shares. Under its IPP Renewal Power Sales Contract with IPA, the Department will be entitled to 71.442% of the capacity of the IPP. In connection with the execution of the IPP Renewal Power Sales Contracts in 2017, the Department also executed successor excess power sales agreements with certain other IPP participants which will continue to make available to the Department additional capacity in the IPP. The increase to the Department's share and additional available capacity in the IPP will become available to the Department when the IPP Renewal Power Sales Contracts take effect on June 16, 2027. Similar to its IPP Contract, the Department will be obligated to pay for the capacity and energy purchased under its IPP Renewal Power Sales Contract on a "take-or-pay" basis as operating expenses of the Power System.

The IPA has issued bonds to finance a portion of the costs of the IPP repowering project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Power Recalls. Under the existing IPP Excess Power Sales Agreements, certain IPP participants have a right to recall from the Department up to 18.168% of the capacity of IPP (currently equal to approximately 327 MW) for defined future summer or winter seasons or both, following no less than 90 days' notice and up to 43 MW of such capacity on a seasonal basis following no less than 90 days' notice. IPP Utah participants will recall 7.820% of the capacity of IPP (equal to 141 MW) from the Department for the summer season which started March 2024 and will end September 2024. The percentage of the capacity of IPP subject to recall will increase to 21.057% (equal to 177 MW) in 2027 upon the effectiveness of the Agreement for Sale of Renewal Excess Power which will take effect on the same day as the Renewal Power Sales Contract described above. The Department can give no assurance that the capacity of IPP subject to recall from the Department under the IPP Excess Power Sales Agreement or the Agreement for Sale of Renewal Excess Power will not be recalled in the future in accordance with the agreement terms.

Fuel Supply. IPA possesses coal supply agreements to fulfill the supply requirement of approximately 4.0 million tons per year. The coal is purchased under a portfolio of fixed price contracts that are of short and long-term in duration. However, as described below, supply chain issues resulting from the loss of coal production in the region and transportation challenges have dramatically reduced coal supply beginning in the later months of 2021 and are expected to impact coal supply for the remaining life of the coal plant. The largest coal producer in Utah experienced a fire in September 2022 and was planning to return to mining in 2024. However, it was announced in November, that the mine is closing indefinitely. The loss of the largest mine, combined with the logistics challenges in Utah, has dramatically reduced supply in the region including to IPA. As a whole, productions remains challenging for the remaining active mines in Utah.

The recent cost of coal delivered to the Intermountain Generating Station is substantially lower than current market prices for the region. However, IPA expects that the costs to fulfill IPP's coal demand will increase due to the scarcity of coal in the Western United States, if IPA is able to secure any additional coal as a replacement for the loss of sources under contract.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between IPA and the Union Pacific Railroad company, and the coal is transported, in part, in IPA-owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks. Both rail service and trucking services have suffered greatly due to a lack of human resources. Neither network is capable of supporting industrial demand; and IPA, like all coal-fired utilities in the United States, has seen large systemic failures in the transportation system.

Historically, IPP was able to maintain a minimum of 60 days of coal in inventory in the event of a coal supply disruption. However, due to the recent challenges in the coal supply chain, the number of days of coal in inventory has periodically declined below that level. As of the mid-December 2023, IPP maintained 39 days of coal in inventory. *{update to come}*

The Department has operational flexibility with respect to its use of IPP; however, the supply chain issues referenced above are likely to impact the operations of IPP and may constrain the Department's ability to utilize such resource.

For more information on the effect of certain environmental considerations on IPP, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Air Quality – Mercury*."

Apex Power Project. The Apex Power Project (the "Apex Power Project") is located in an unincorporated area of Clark County, north of Las Vegas, Nevada. The Apex Power Project includes the Apex Generating Station, which is a combined cycle generating station consisting of one 238 MW, nameplate rating, steam turbine generator, and two simple cycle, 203 MW, nameplate rating, combustion turbine generators. The Apex Power Project also includes heat recovery equipment, air inlet filtering, closed cycle cooling system, emission control system, exhaust stack, distributed control system, all necessary noise control equipment, and its associated real property. The Apex Generating Station has a net maximum capacity of 578 MW and a net dependable capacity of 483 MW. In March 2014, SCPPA acquired the Apex Power Project for the benefit of the Department, and the Department is entitled to 100% of the capacity and energy of the Apex Power Project under a take-or-pay power sales contract with SCPPA. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Hoover Power Plant.

General. The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility at Lake Mead, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Power Plant consists of 17 generating units and two service generating units with a total installed capacity of approximately 2,074 MW, and a minimum capacity of 650 MW. The Department has a power purchase agreement with the United States Department of Energy Western Area Power Administration ("Western") for 23.90% of total contingent capacity and 14.65% of the firm energy from the Hoover Power Plant through September 2067. The facility is owned and operated by the United States Bureau of Reclamation (the "Bureau of Reclamation").

Environmental Considerations. The lower Colorado River has been included in a critical Habitat Designated Area. This required the Bureau of Reclamation to prepare and file with the United States Fish and Wildlife Service (the "USFWS") a Biological Assessment on the effect of its operations of the lower Colorado River on endangered species therein (the "Biological Assessment"). After the Biological Assessment was filed, the USFWS issued a Biological and Conference Opinion regarding the Bureau of Reclamation's operations and outlined remedial actions to be taken to correct adverse effects to endangered species. Such remedial actions could affect the operation of the Hoover Power Plant, which would in turn affect the Hoover Power Plant customers, including the Department. The Department believes that any impact of the Biological and Conference Opinion on future operations will be minor; however, there is a possibility that future regulatory action will recommend major remediation actions that could have a material impact on the Hoover Power Plant customers' available capacity from the Hoover Power Plant. The Hoover Power Plant customers, including the Department, together with certain other parties, have implemented a plan in cooperation with the Bureau of Reclamation and the USFWS to mitigate negative effects on the Hoover Power Plant's energy production.

Palo Verde Nuclear Generating Station.

General. PVNGS is located approximately 50 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units (numbered 1, 2 and 3), with a net maximum capacity of 1,333 MW (unit 1), 1,336 MW (unit 2) and 1,334 MW (unit 3) and a dependable capacity of 1,311 MW (unit 1), 1,314 MW (unit 2) and 1,312 MW (unit 3). PVNGS's combined design capacity is 4,003 MW and its combined dependable capacity is 3,937 MW. Each PVNGS generating unit has been operating under 40-year Full-Power Operating Licenses granted by the Nuclear Regulatory Commission (the "NRC") expiring in 2025, 2026, and 2027, respectively. In

April 2011, the NRC approved PVNGS's license renewal application, allowing the three units to extend operation for an additional 20 years until 2045, 2046 and 2047, respectively.

Arizona Public Service Company ("APS") is the operating agent for PVNGS. On average, PVNGS has provided over 3.1 million MWhs of energy annually to the Power System. The Department has a 5.7% direct ownership interest in the PVNGS (approximately 224 MW of dependable capacity). The Department also has a 67.0% generation entitlement interest in the 5.91% ownership share of PVNGS that belongs to SCPPA through its "take-or-pay" power contract with SCPPA (totaling approximately 156 MW of dependable capacity), so that the Department has a total interest of approximately 380 MW of dependable capacity from PVNGS. Co-owners of PVNGS include APS; the Salt River Project; Edison; El Paso Electric Company; Public Service Company of New Mexico; SCPPA and the Department.

Nuclear Regulatory Commission. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities.

The aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan prompted the U.S. nuclear industry to form a task force under the direction of PVNGS's Chief Nuclear Officer to take immediate actions in ensuring the reliability of all U.S. nuclear plants. PVNGS instituted improvements driven by the findings from such task force. Among these improvements, is a staging of "flex" equipment, which includes mobile pumps, generators, hoses, and fire trucks that enable PVNGS to shift cooling water through the plant and power critical equipment in the event of a disaster.

Decommissioning Costs. The owners of PVNGS have created external trusts in accordance with the PVNGS participation agreement and NRC requirements to fund the costs of decommissioning PVNGS. Based on the 2022 annual funding status report which is based on a 2019 study of decommissioning costs, which is the most recent estimate available, the Department estimates that its share of the amount required for decommissioning PVNGS relating to the Department's direct ownership interest in PVNGS was approximately 71% funded and that its share of decommissioning costs through SCPPA was 85% funded. The Department's direct share of costs is $195.2 million and SCPPA's share is $209.3 million, of which the Department's portion is $140.3 million or 67%. Under the current funding plan, the Department estimates that its share of the decommissioning costs relating to the Department's direct ownership interest in PVNGS will be fully funded by accumulated interest earnings by the extended license expiration date of 2047. Such estimates assume 7% per annum in future investment returns and a 5% per annum cost escalation factor. The Department has received and is receiving less than a 7% per annum investment return on the decommissioning funds and cost increases have been averaging less than 5% per annum. No assurance or guarantee can be given that investment earnings will fully fund the Department's remaining decommissioning obligations at current estimated costs or that the decommissioning costs will not exceed current estimates. For a discussion of the Department's nuclear decommissioning trust fund and other investments held on behalf of the Department, see "GENERAL – Investment Policy and Controls."

Nuclear Waste Storage and Disposal. Generally, federal and state efforts to provide adequate interim and long-term storage facilities for low-level and high-level nuclear waste have proven unsuccessful to date. Although federal and state efforts continue with respect to such storage and disposal facilities, the Department is not able to predict the schedule for the permanent disposal of radioactive wastes generated at PVNGS. Since the spent fuel pools ran out of storage capacity, an independent spent fuel storage installation was built to provide additional spent fuel storage at the site while awaiting permanent disposal at a federally developed facility. The installation uses dry cask storage and was designed to accept all spent fuel generated by PVNGS during its lifetime. As of December 31, 2023, 152 casks, each containing 24 spent fuel assemblies, and 24 new casks, each containing 37 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel at a time, have been stored. Storage costs are partially paid using funds received by APS pursuant to a settlement agreement with the United States government relating to nuclear waste disposal fees.

Mohave Generating Station – Operations Ceased. The Mohave Generating Station was a coal-fired electric generating station located near Laughlin, Nevada, that ceased operations in 2005. The Department owned a 30% interest in the Mohave Generating Station and still owns a 30% interest in the site. The other co-owners are Edison and NV Energy (formerly known as Nevada Power Company). The Mohave Generating Station generating units were removed from service at the end of 2005. A major plant decommissioning was completed in 2012. As required by the Nevada Division of Environmental Protection, minor cleanup, ground water monitoring and upkeep of the plant site will continue for a number of years after the decommissioning to ensure that the integrity of the coal ash landfill is maintained and that the groundwater is protected from contamination. In accordance with an approved site disposition plan, the co-owners of the Mohave Generating Station have made approximately 80% of the property of the Mohave Generating Station available for public sale. Any sales transaction will require approval from the Board and City Council. The remaining property would be retained by the co-owners for ongoing monitoring, maintenance, and environmental compliance purposes. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Coal Combustion Residuals*."

Navajo Generating Station – Operations Ceased. The Navajo Generating Station was a coal-fired, electric generating station located near the City of Page, Arizona, that ceased operations in 2019. The Salt River Project Agricultural Improvement and Power District, a political subdivision of the state of Arizona, and the Salt River Valley Water Users' Association, a corporation (together, the "Salt River Project") is the operating agent of the Navajo Generating Station. The Department sold its interest in the Navajo Generating Station in 2016, however the Department is still responsible for its portion of decommissioning costs.

LA100 Study

In accordance with three City Council motions passed in 2016 and 2017, the Department partnered with the NREL to perform the "LA100: The Los Angeles 100% Renewable Energy Study" (the "LA100 Study"). This unprecedented, three-year study identified several pathways that would allow the City to achieve a 100%-renewable-energy portfolio no later than 2045. The NREL identified four overall scenarios with various modeling assumptions for the Department to achieve its sustainability goals, including one scenario to achieve its goals by 2035. The NREL also analyzed how the scenarios could affect the region's air quality, GHG emissions, public health, jobs, and economic activity. At the direction of the City Council, the study incorporated the CalEnviroScreen, allowing the NREL to identify pathways that will be not only economical for the utility but also equitable for communities.

The LA100 Study has yielded a tremendous amount of data and new, state-of-the-art models that provide the Department with a variety of perspectives on approaches toward 100% renewable energy. The results of the LA100 Study will continue to inform the Department's internal planning processes, including its Strategic Long-Term Resource Plan and other public outreach efforts that are designed to ensure a just and equitable transition for the City. The Financial Services Organization of the Department has conducted a preliminary rate analysis to determine the rate impacts for each of the scenarios in the LA100 Study. However, more in-depth analysis on the specific path is needed to ascertain more accurate rate analysis. The total cumulative cost through 2045 of new investment needed to achieve the suite of modeled scenarios ranges from approximately $57 billion to $87 billion, depending on the scenario, load projection, and the target year.

At the conclusion of the LA100 Study, it was determined that the LA100 Study provided various ways to reach 100% clean energy but it did not fully address the topic of equity as part of the transition. As a result, the LA100 Equity Strategies Study was commissioned by the Board. The independent study was conducted by the NREL and by UCLA with focused research in five priority areas: (1) affordability and energy burdens; (2) access to and use of energy technologies, programs, and infrastructure; (3) health, safety, and community resilience; (4) jobs and workforce development; and (5) inclusive community involvement. The ultimate goal of the LA100 Equity Strategies Study is for all communities across the City to share in the benefits and the burdens of the clean energy transition and to identify what policies should be put in place to achieve such outcomes. The LA100 Equity Strategies study report was released in November 2023. The report details a number of findings, recommendations and strategies addressing inequities in the clean-energy transition and is designed to assist the

Department to make data-driven, community-informed decisions for equitable investment and program development towards achieving a 100% carbon-free energy portfolio.

Renewable Power Initiatives

The Department expects to continue to procure a renewable power resource portfolio that satisfies applicable State requirements, the main provisions of which are currently contained in the California Renewable Energy Resources Act ("SBX 1-2"), the California Global Warming Solutions Act of 2006 ("AB 32" or the "Global Warming Solutions Act"), the Clean Energy and Pollution Reduction Act of 2015 ("SB 350"), and the 100 Percent Clean Energy Act of 2018 ("SB 100"). For a discussion of certain State legislation and regulations affecting the Department, including AB 32, SB 350, SB 1368, SBX 1-2, SB 100, and the Clean Energy, Jobs, and Affordability Act of 2022 ("SB 1020"), see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments." Certain components of the Department's renewable power resource portfolio are described below. Available capacity with respect to such renewable power resources will vary as they are intermittent resources. Wind power, both obtained through power purchase agreements and resources owned by the Department, provided 11% and 13% of the Department's energy in 2021 and 2022, respectively, or about one-third of the renewable energy, which comprised 35% and 36% of the total energy mix in 2021 and 2022, respectively, as reflected in the Department's Annual Power Content Label for such years.

Large Scale Wind Energy. Through power purchase agreements, the Department has secured large scale wind farm output in a number of areas to provide a diversity of wind power resources. Such wind energy for the Department is being generated in wind farms located in the States of California, Oregon, Washington, Utah, and Wyoming, and New Mexico. Such power purchase agreements provide for an aggregate of 1,143 MW of wind energy. In addition to these power purchase agreements, wind farms with output of approximately 880 MW are also subject to Department options to purchase such assets.

Certain of these projects are described as follows:

Milford Wind Corridor Phase I Project. The Milford Wind Corridor Phase I Project (the "Milford I Project") began commercial operation in November 2009 and consists of SCPPA's purchase of all energy generated by a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah (the "Milford I Facility"), for a term expiring in November 2029 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase I, LLC. Energy from the Milford I Facility is delivered to SCPPA over an approximately 90-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 6,764,301 MWhs of energy from the Milford I Facility over the delivery term. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 92.5% share of the Milford I Project on a "take-or-pay" basis as an operating expense of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Milford Wind Corridor Phase II Project. The Milford Wind Corridor Phase II Project (the "Milford II Project") began commercial operation in May 2011 and consists of SCPPA's purchase of all energy generated by a 102 MW nameplate capacity wind farm comprised of 68 wind turbines located near Milford, Utah (the "Milford II Facility"), for a term expiring on June 30, 2031 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase II, LLC. Energy from the Milford II Facility is delivered to SCPPA over an approximately 88-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 4,467,600 MWhs of energy from the Milford II Facility over the delivery term. In connection with the issuance of bonds relating to the Milford II Project, the Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 95.098% share of the Milford II Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 4.902% output entitlement share of Milford II Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Linden Wind Energy Project. The Linden Wind Energy Project (the "Linden Project") began commercial operation in June 2010 and consists of SCPPA's acquisition of a 50 MW nameplate capacity wind farm comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington. The Linden Project was developed and constructed by Northwest Wind Partners, LLC ("Northwest Wind"). SCPPA acquired the project from Northwest Wind pursuant to the terms of an asset purchase agreement between SCPPA and Northwest Wind. Energy from the Linden Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Linden Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the acquisition of the Linden Project. The Department has entered into a power sales agreement with SCPPA for a term expiring in 2035 (unless earlier terminated) that provides for the Department to pay its 90.00% share of the Linden Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 10.00% output entitlement share of the Linden Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the "Windy Point Project"). The Windy Point Project is owned and operated by Windy Flats Partners, LLC ("Windy Flats"). Pursuant to a power purchase agreement with Windy Flats, SCPPA has agreed to purchase from Windy Flats all energy from the Windy Point Project for a delivery term that was originally expiring in 2030 (unless earlier terminated). In March 2023, an amendment to the original power purchase agreement was approved which extended the delivery term for an additional four years, to 2034. Energy from the Windy Point Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs of energy from the Windy Point Project. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay its 92.37% share of the Windy Point Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 7.63% output entitlement share of Windy Point Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Pine Tree Wind Project. The Pine Tree Wind Project (the "Pine Tree Wind Project") is a wind generating facility north of Mojave, California, consisting of 90 wind turbines owned and operated by the Department. The Pine Tree Wind Project began commercial operation in June 2010 and has a nameplate capacity of 135 MW. As part of normal operating procedures, the Department staff has notified federal and State authorities concerning mortalities of golden eagles. Since June 2009, the Department staff has found nine golden eagle carcasses in the proximity of the Pine Tree Wind Project. The Department has completed advanced monitoring studies and surveys to research golden eagle behavior within the vicinity of the Pine Tree Wind Project and to determine potential causes of the eagle mortalities and mitigation options relating to the golden eagles. The Department previously conducted tests using radar and automated deterrent technology in detecting and deterring golden eagles and other birds of prey at the Pine Tree Wind Project. Golden eagles are a protected species, and the death or injury to a golden eagle in some circumstances can result in fines and penalties, including criminal sanctions. As of June 2017, the Department entered into a settlement agreement with the USFWS to address the golden eagle mortalities at the Pine Tree Wind Project. The Department completed its golden eagle research and development study as required by the settlement agreement and submitted the final summary report to USFWS in September 2020. On December 29, 2020, the Department received a letter from the USFWS indicating that the Department had fulfilled the terms of the settlement agreement with respect to the research and development study, payment, and meet and confer with USFWS staff. The Department is still coordinating with the USFWS to obtain an incidental take permit for golden eagles as a separate requirement under the settlement agreement. In order to protect condors, a protected species under State and federal law, the Department has implemented a condor detection protocol that includes turbine curtailment when condors are observed in the immediate area. Additionally, the Department has prepared a condor conservation plan and obtained an incidental take permit for California condors on November 28, 2023. The condor conservation plan outlines the avoidance measures that are currently being implemented and the proposed compensatory mitigation measures in an effort to protect and address the declining condor population.

Red Cloud Wind Project. In November 2020, the Department entered into a power sales agreement with SCPPA to purchase renewable energy purchased by SCPPA from the Red Cloud Wind Project located in New Mexico (the "Red Cloud Wind Project"). Pursuant to a power purchase agreement with Red Cloud Wind, LLC, SCPPA purchases 331 MW of renewable energy to be delivered to the Department at the Navajo 500 kV Switching Station for a 20-year term. The Red Cloud Wind Project was developed by Pattern Energy and commenced commercial operation on December 22, 2021. The Red Cloud Wind Project is expected to deliver an annual average of approximately 1,333,000 MWhs of renewable energy to the Department.

Distributed Energy Resource Programs. The Department has implemented the following programs to encourage the development of solar energy in Los Angeles: (i) the Solar Incentive Program in which residential and commercial customers are encouraged to install eligible solar photovoltaic systems with incentive funding provided by the Department, which ended in December 2018; (ii) Department-built solar projects on City-owned properties; (iii) the Solar Rooftops Program, which places Department-owned solar panels on qualifying residential rooftops in exchange for predefined lease payments to the customer; (iv) a Feed-in-Tariff ("FiT") program, launched on February 1, 2013, which has a total installed capacity of 101.7 MW comprised of 4 MW of solar photovoltaic generation in the Owens Valley and 4 MW of renewable landfill gas generation, and 93.7 MW of photovoltaic generation installed within the Department's service territory and connected to the Department's electric distribution system; (v) the Shared Solar Program ("SSP"), which enables residential customers living in multi-family dwellings to fix a portion of their electric bills through Department solar installations; (vi) the Virtual Net Energy Metering ("VNEM") pilot program, which launched in March 2021 and allows developers or building owners to install solar arrays on multi-family dwelling unit buildings and split the energy sales proceeds with tenants; and (vii) the FiT Plus program, which facilitates the installation of battery storage with existing and new FiT projects.

Under the California Solar Initiative ("SB-1"), POUs are required to establish programs supporting the stated goal of the legislation to install 3,000 MW of photovoltaic capacity in the State, and to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer funded incentives. The Solar Incentive Program used $339 million of ratepayer funds mandated by SB-1 to administer the program and subsidize customers for customer-owned solar projects to offset their electricity use. As of December 2018, the Department committed all funds available for this program for 279.7 MW of installations.

The Department currently has 25.9 MW of Department–built solar projects on City-owned properties. The Adelanto Solar Power Project is a 10 MW solar photovoltaic system placed into commercial operation in June 2012, which is expected to deliver 450,000 MWhs of energy over 25 years, located at the existing Adelanto Switching and Converter Station near Adelanto, California. In addition, the Pine Tree Solar Project was placed into commercial operation in March 2013. The Pine Tree Solar Project is an 8.5 MW solar photovoltaic system expected to deliver 350,000 MWhs of energy over 25 years, located at the Department's existing Pine Tree Wind Project in the Tehachapi Mountains, California. The remaining 6.9 MW includes installations spread across various City owned properties in the Los Angeles Basin as well as a 500kW system in the Owens Valley.

The Department has entered into the following 13 power purchase agreements ("PPAs") for the purchase of renewable energy from 1,495 MW of solar photovoltaic projects:

- One PPA with an option to purchase is a 25-year contract with K Road Moapa Solar, LLC, which changed its name to Moapa Southern Paiute Solar, LLC, for 250 MW, delivering up to 618,000 MWhs a year to the Department. The solar facility is located on Moapa Band of Paiute Indians tribal land north of Las Vegas, Nevada. The Department acquired the approximately 5.5-mile transmission line associated with the facility, which achieved full commercial operation in December 2016.

- The second PPA with an option to purchase is a 20-year contract through SCPPA for 210 MW of the Copper Mountain Solar 3 Project developed by an affiliate of Sempra U.S. Gas and Power. Copper Mountain Solar 3 Project is near Boulder City, Nevada and is expected to deliver 515,000 MWhs of renewable energy a year to the Department and began full commercial operation in April 2015.

- The third PPA with an option to purchase is a 20-year contract for 60 MW of the RE Cinco Solar Project developed by Recurrent Energy, an affiliate of Canadian Solar Inc. RE Cinco Solar Project is near the Mojave Desert in Kern County and is expected to deliver an annual average of 182,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in August 2016.

- The fourth PPA with an option to purchase is a 25-year contract through SCPPA for 105 MW of the Springbok I Solar Farm Project developed by Avantus (formerly 8Minutenergy). Springbok I Solar Farm Project is near the Mojave Desert in Kern County and is expected to deliver an average of 284,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2016.

- The fifth PPA with an option to purchase is a 27-year contract through SCPPA for 155 MW of the Springbok II Solar Farm Project, which is adjacent to the Springbok I Solar Farm Project and was developed by Avantus. Springbok II Solar Farm Project is expected to deliver an average of 420,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in September 2016.

- The sixth PPA with an option to purchase is a 27-year contract through SCPPA for 90 MW of the Springbok III Solar Farm Project, which is adjacent to the Springbok I and Springbok II Solar Farm Projects and was developed by Avantus. Springbok III Solar Farm Project is expected to deliver an average of 240,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2019.

- The seventh PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 1, is a 25-year contract through SCPPA for 175 MW of energy and 131.25 MW/525 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 1 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 2, and is being developed by Avantus, with commercial operation expected in the third quarter of calendar year 2024. Eland Solar & Storage Center, Phase 1 is expected to deliver an average of approximately 702,000 MWhs of renewable energy a year to the Department.

- The eighth PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 2, is a 25-year contract through SCPPA for 200 MW of energy and 150 MW/600 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 2 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 1, and is being developed by Avantus, with commercial operation expected in the first quarter of calendar year 2025. Eland Solar & Storage Center, Phase 2 is expected to deliver an average of approximately 803,000 MWhs of renewable energy a year to the Department.

- The ninth through thirteenth PPAs are related to the Beacon Solar Project Sites 1 thru 5. The Beacon Property, located in the Mojave Desert near the Pine Tree Wind Project, is a 2,500-acre property purchased by the Department from Nextera Energy Resources in 2012. Five PPAs and associated agreements have been executed for the development of five solar sites totaling 250 MW within the Beacon Property. Each of the five solar sites achieved commercial operation at different dates within the years 2016 and 2017, and are expected to generate an average of 581,000 MWhs per year of solar energy in aggregate over a term of 25 years. The PPAs provide the Department with an option to purchase the solar projects after the developers have realized the federal tax benefits.

In connection with the implementation of these PPAs, the Department has upgraded certain transmission assets to accommodate these projects in the Barren Ridge area. See "– Transmission and Distribution Facilities – *Barren Ridge Renewable Transmission Project*."

The Department's 450 MW FiT program allows the Department to purchase, through power purchase contracts, electricity generated from program participants' renewable energy generating sources. Such sources are to be located within the Department's service territory and connected to the Power System. The energy purchased through the FiT program is expected to count toward the Department's RPS targets. As discussed above, as part of the PPAs for solar development on the Beacon Property, the Beacon Solar developers installed additional solar in the Department's service territory. The Department has allocated the capacity of the original 150 MW FiT program. The Department obtained approval from the City Council to expand the FiT program by an additional 300 MW of capacity. The first 50 MW offering of this expansion was authorized in January 2020. In addition to increasing the FiT program from 150 MW to 450 MW over a number of years, the FiT program will now accommodate all renewable technologies approved by the CEC and expand each project's maximum capacity, previously set at 3 MW, to 10 MW. The FiT Plus and VNEM pilot programs will use 10 MW and 5 MW of the existing FiT capacity, respectively. The FiT Plus pilot program encourages the installation of battery energy storage with local solar projects, making solar energy dispatchable, while increasing the power grid's reliability and resiliency. The VNEM pilot program facilitates the installation of solar projects on multifamily dwellings, and allows renters to readily access the benefit of these systems. In April 2023, the Board approved the use of an additional 75 MW of capacity for the FiT programs and the Department introduced a FiT Carport and Canopy Incentive program. Out of the 450 MW authorized by City Council, the use of a total of 275 MW has been approved across all FiT programs.

Geothermal Development. The Department executed a power sales agreement with SCPPA for 84.62% of the energy output, or 114 GWhs annually, of the Don A. Campbell Phase I Geothermal Energy Project (the "Don Campbell Phase I Project"), which began commercial operation on January 1, 2014. The Don Campbell Phase I Project consists of SCPPA's purchase of all energy generated by a 16.2 MW nameplate capacity binary geothermal power plant comprised of eight drilled commercial wells located in Mineral County, Nevada for an initial delivery term of 20 years expiring December 31, 2033.

In addition, in April 2015, the Department executed a power sales agreement with SCPPA for 100% of the energy output, or 135 GWhs annually, of the Don A. Campbell Phase II Geothermal Energy Project (the "Don Campbell Phase II Project" and, together with the Don Campbell Phase I Project, the "Don Campbell Projects"), which expires in September 2035 and is located in the same vicinity as the Don Campbell Phase I Project. The Don Campbell Phase II Project is an expansion of the Don Campbell Phase I Project by the same developer, Ormat Nevada, Inc., and began commercial operation in September 2015. The nameplate capacity for the Don Campbell Phase II Project is 16.2 MW.

In addition to the Don Campbell Projects, the Department executed a power sales agreement with SCPPA in September 2013 for a share of the output purchased by SCPPA from the Heber-1 Geothermal Project (the "Heber-1 Project"). The energy delivery commencement date was February 2, 2016 for an initial term of ten years. The Heber-1 Project is an existing geothermal complex which includes the Heber-1 double flash steam unit and the Gould 1 bottoming binary unit, located in Imperial County, California. The net energy generated from the Heber-1 Project is expected to be 46 MW. The Department's share was 66.67% (30.68 MW) in the first three years and is 78.0% (35.88 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 285 GWhs annually.

In addition, the Department executed a power sales agreement with SCPPA in December 2016 for a share of the output purchased by SCPPA from the Ormesa Geothermal Complex Project (the "Ormesa Project"). The energy delivery commencement date was January 1, 2018 for a term of 25 years, ending on December 31, 2042. Similar to the Heber-1 Project, the Ormesa Project is an existing geothermal complex which includes two active binary units and one active bottoming unit, located in Imperial County, California. The generation capacity of the project is 35 MW. The Department's share is 85.71% (30 MW) of the energy output. The equivalent average energy delivered to the Department is expected to be 250 GWhs annually.

In May 2017, the City Council approved a power sales agreement with SCPPA for 100% of the output purchased by SCPPA from the Ormat Northern Nevada Geothermal Portfolio Project. At full service, this project provides the Department with approximately 163.54 MW of renewable geothermal energy from six power plants in various locations in Nevada. This amount is expected to represent approximately 5% of the Department's renewable energy portfolio in 2030. Energy delivery from the project stepped up in three phases from December 31, 2017 to December 31, 2022 as follows: 60 MW minimum and 85 MW maximum by December 31, 2018 (which was achieved), cumulative 90 MW minimum and 130 MW maximum by December 31, 2020 (which was achieved), and cumulative 135 MW minimum and 185 MW maximum by December 31, 2022 (which was achieved). After December 2022, the maximum annual energy received by the Power System from the project is expected to be 1,620 GWhs. The power sales agreement with SCPPA expires in December 2043.

Biomass Development. In March 2018, the City Council approved a power purchase agreement with SCPPA for a share of the output of the ARP-Loyalton Biomass Project in Sierra County, California, which began commercial operation in April 2018. SCPPA partnered with other State POUs to purchase a total of 18 MW of capacity for a term of five years towards satisfaction of procurement obligations under SB 859. The Department's share of the ARP-Loyalton Biomass Project was 8.9 MW. Following the bankruptcy of the operator and its parent company, energy deliveries from the ARP-Loyalton Biomass Project ceased in February 2020 and did not resume. The power purchase agreement for the output of the project expired by its terms on April 19, 2023. The Department has also contracted with SCPPA to purchase 5.4 MW of rated capacity from the Roseburg SB 859 biomass project. These two power purchase arrangements allow the Department to meet its requirement to purchase 14.3 MW of rated capacity from biomass sourced energy facilities in order to comply with SB 859. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Biomass Legislation*."

Energy Storage Development. In connection with the implementation of State law, the Department is developing viable and cost-effective energy storage systems. The goals of the energy storage systems include reducing emissions of GHGs, reducing demand for peak dispatchable generation and improving the reliability of the electric grid. Although energy storage systems themselves are not considered renewable resources, they facilitate the integration of renewable resources into the Power System. To date, the Department has implemented several small energy storage systems throughout the Power System, including:

- The 12 kW Fire Station 28 Battery Energy Storage System (BESS), located near the Porter Ranch area, commenced operation in October 2017.
- The 60 kW Lithium-Ion BESS, located at the Department's La Kretz Innovation Center, was integrated into the existing solar panel system in 2016.
- The 55 kW Lithium-Ion BESS, located at the Department's Truesdale Training Center, was commissioned in 2017.
- The 20 MW Beacon utility-scale BESS project, located on the Beacon Property, which commenced operation in October 2018.
- The 1.5 MW Lithium-Ion BESS, located at the Springbok 3 solar plant, installed in October 2019 for technical and operational performance demonstrations.
- The 100 kW Lithium-Ion BESS and 100 kW Flow BESS, located at the Department's headquarters (John Ferraro Building), which commenced operation in November 2019.

In addition, as discussed above, in 2020, the Department entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. Phase 1 is expected to be commissioned in 2024 and Phase 2 is expected to be commissioned in 2025.

See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Energy Storage Legislation*."

The Department issued a Standalone Energy Storage RFP, through SCPPA, for various technologies, including Long Duration Energy Storage (LDES). Following review of the proposals received, the Department will begin negotiations with the vendor(s) that meets the Department's requirements.

Green Power Program. The Department offers its Green Power Program to all customers at a premium over standard rates. "Green Power" is produced from renewable resources such as solar and wind energy, rather than fossil-fueled or nuclear generating plants. This voluntary program includes customer-selected levels of Green Power purchases, subject to specified minimum requirements. Approximately 9,124 Department customers subscribed to the Green Power Program as of December 2023. The Department is working on Green Power Program improvements that are intended to increase both the number of participants and the amount of green energy purchased through the program.

Other Renewable Energy Project Developments. The Department, on its own and through SCPPA, has received proposals from renewable energy resources such as solar photovoltaic, wind, biomass, small hydro, solar thermal and geothermal power via solicitations. The Department is also considering opportunities related to utilization of land located in the Owens Valley area of the State for solar, wind or geothermal and for improved transmission access to geothermal energy. In addition, as part of then Mayor Eric Garcetti's announcement in February 2019 that certain natural gas units will be phased out and replaced with renewable energy producing assets, the Department will be exploring options over the next few years to develop such assets for the Power System. See "THE POWER SYSTEM – Department Owned Facilities – *Once-Through-Cooling Units Phase-Out*" for more information. Additional renewable energy resources will be obtained; however, the Department's participation in or acquisition of any specific renewable energy project will be subject to City Council approval when required, and the costs and schedules for implementation and feasibility of any such alternative energy projects may vary materially from initial projections.

L.A.'s Green New Deal. On February 10, 2020, then Mayor Eric Garcetti released his Executive Directive No. 25 implementing L.A.'s Green New Deal. As part of this directive, the City expects the Department to provide equitable access to clean energy programs, build zero carbon microgrids in City owned infrastructure, deploy smart meters City-wide and institute other similar initiatives. The Department is studying how to implement this directive and other renewable power related directives and the effect they will have on the finances and operations of the Power System.

On April 19, 2021, then Mayor Eric Garcetti declared in his 2021 Los Angeles State of the City address his goal for the Department to provide an energy mix that is 80% renewable and 97% GHG-free resources by 2030, a full six years ahead of the L.A. Green New Deal, and to use the LA100 Study as a guide to fulfill President Biden's energy vision, with a goal of 100% carbon-free energy by 2035. To achieve these goals, the then Mayor referenced the Department's transition of Scattergood Generating Station to clean energy alternatives, the construction of the Red Cloud Wind Project in New Mexico, the partnership with the Navajo Nation for solar energy, and the supply of IPP with green hydrogen fuel. For more information on the LA100 Study, see "THE POWER SYSTEM – *LA100 Study*." For more information on the transition of Scattergood Generating Station, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board." For more information on the Red Cloud Wind Project, see "THE POWER SYSTEM – Renewable Power Initiatives – *Red Cloud Wind Project*." For more information on the Navajo Project, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units - *Navajo Generating Station – Operations Ceased*." For more information on the re-powering of IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project – Intermountain Generating Station upon the termination of the IPP Contract*."

The Clean Grid LA Plan Update was presented to the Board on May 11, 2021. The Clean Grid LA Plan Update is a 10-year roadmap that aligns with the LA100 Study to assist the Department with its clean energy goals. Elements of the Clean Grid LA Plan include providing 80% renewable and 97% GHG-free resources by 2030, accelerating transmission projects, transforming local generation, accelerating energy storage, and deploying distributed energy resources equitably. The Department plans to construct a combined cycle generating system capable of utilizing green hydrogen at Scattergood Generating Station which is expected to be in-service by 2029. Moreover, the Department continues to assess the potential opportunities for additional green hydrogen-fueled electricity generation across the coastal, in-basin generating stations. In addition to the Scattergood Green Hydrogen-Ready Modernization Project, the Department plans to convert Haynes Unit 8 from once-through cooling to wet cooling by 2027.

To fully understand the opportunities for developing a comprehensive green hydrogen economy in California, the Department is engaged with the Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES"). ARCHES is a public-private partnership led by the California Governor's Office of Business and Economic Development (GO-Biz) that is seeking to secure and maximize federal, state, and private funding for a California hydrogen hub. Most significantly, ARCHES is seeking federal funding through the federal Department of Energy's Regional Clean Hydrogen Hubs program which includes up to $7 billion to establish no more than 10 regional hydrogen hubs across the country. Through the ARCHES framework, the Department is collaborating with partners across the region and advocating for the development of local green hydrogen economy.

On May 19, 2022, the City Council voted to instruct the Department and the Port of Los Angeles ("POLA") to coordinate a local effort to create and submit a proposal to the Department of Energy proposing the Greater Los Angeles area for consideration as a regional green hydrogen hub. Through ARCHES, the Department and its partners submitted an application that details a proposed clean hydrogen ecosystem in California comprised of new and existing projects. On October 13, 2023, President Biden and Energy Secretary Jennifer Granholm announced $7 billion in awards for seven regional clean hydrogen hubs, of which the California-centered hub will receive $1.2 billion. The Department continues to work with both public and private entities to develop the necessary partnerships and governance structures, conduct market and system value benefit studies, and gather stakeholder feedback. The development and outcomes from this effort will be foundational to the Department's decarbonization efforts at the Los Angeles Basin Stations.

On September 1, 2021, the City Council voted to instruct the Department to "prepare a Strategic Long-Term Resource Plan that achieves 100% carbon-free energy by 2035, in way that is equitable and has minimal adverse impact on ratepayers." In addition, the City Council instructed the Department to "create a long term hiring and workforce plan . . . ensuring project labor agreements, [payment of] prevailing wage[s] . . . [with] hiring from environmentally and economically disadvantaged communities." The Department initiated its Strategic Long-Term Resource Plan in September 2021 with a stakeholder process and incorporating the Clean Grid LA Plan and key findings from the LA100 Study for Board consideration.

As previously noted, the Department released a final version of the 2022 Strategic Long-Term Resource Plan in July 2023. The 2022 Strategic Long-Term Resource Plan models three cases for achieving 100% carbon-free energy by 2035, as well as a reference case used for comparison purposes, that represents the minimum investments needed to comply with the requirements of SB 100 (see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments"). The 2022 Strategic Long-Term Resource Plan utilizes the same modeling methodology and approach as the LA100 Study. For each of the three cases modeled, the net present value of the estimated total cumulative bulk power portfolio cost across the study horizon of 2022 through 2045 is in excess of $80 billion. The 2022 Strategic Long-Term Resource Plan represents only a conceptual plan and encompasses numerous challenges related to availability of technology, implementation feasibility, system reliability and affordability. The 2022 Strategic Long-Term Resource Plan does not include potential cost savings from new sources of funding such as the federal Inflation Reduction Act, the federal Bipartisan Infrastructure Law, and state and federal grants. The next iteration of the Department's Strategic Long-Term Resource Plan, the 2024 Strategic Long-Term Resource Plan will be an update to the 2022 Strategic Long-Term Resource Plan, and will focus on understanding rate drivers and additional clean energy opportunities to refine and optimize costs over the long-term.

Energy Efficiency

General. The Charter authorizes the Department to engage in and finance activities related to the efficient use of energy and a number of State laws expressly require utilities such as the Department to collect and spend funds for these activities. The Department has a commitment to energy efficiency and continues to pursue cost-effective means of reducing or avoiding the need to generate electricity (particularly during peak periods). These activities defer the need to acquire costly new generating facilities, improve the value of electric service to customers and increase the Department's overall load factor, thereby reducing or avoiding negative environmental impacts from power generation. Moreover, State laws enacted in 2005 and 2006 require POUs, such as the Department, in procuring energy, to first implement all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible, and to provide annual reports to customers and to the CEC describing their investment in energy efficiency and demand reduction programs. AB 2021, which became a law in 2007, required IOUs and POUs to identify energy efficiency potential and establish annual efficiency targets to enable the State to meet the goal of reducing total forecasted electricity consumption by 10% by 2020. The Department adopted a goal in August 2014 of achieving up to 15% energy savings by the end of 2020, which was achieved. The Department is now focused on a goal of achieving additional energy savings of 3,431 GWhs from 2023 to 2035, surpassing the 2,628 GWhs of projected savings reflected in the LA100 Study.

Program and Portfolio Highlights. The Department's balanced portfolio of programs provides opportunities for all customers to benefit from cost effective energy efficiency. This approach targets large energy users and hard-to-reach customers who would not otherwise be able to invest in energy efficiency services, broadly addresses energy end uses in the built environment, focuses on reducing consumption during times of peak demand, and provides quality job opportunities for the local workforce. These programs include financial incentives for the installation of a variety of efficiency measures, free energy saving products, technical assistance incentives for business and industry, codes and standards, and education and awareness. The following list provides examples of programs that demonstrate the portfolio's ability to reach all customer types.

Comprehensive Affordable Multifamily Retrofits. The Comprehensive Affordable Multifamily Retrofits (the "CAMR") program provides low-income tenants and affordable housing property owners access to energy efficiency retrofits, building electrification measures, and on-site solar installation. The participating housing providers receive free energy assessments and assistance in scoping retrofit projects based on opportunities for energy savings, cost reductions, and GHG emissions reduction. Participating properties must meet affordability requirements of at least 66% of households at or below 80% of the area median income, consist of five or more units, and install energy improvements that equate to at least 10% in energy savings.

Efficient Product Marketplace. The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point of sale credit option to customers during their online purchases, eliminating the need for completing a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare and choose offers from a list of local third-party vendors.

Food Service Program. For in-store purchases, the Food Service Program offers an instant rebate as a line item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment. Beginning in 2024, the Food Service Program will start offering electrification incentives for all electric commercial cooking equipment & appliances.

Customer Performance Program. The Custom Performance Program (the "CPP") provides cash incentives for energy savings achieved through the implementation and installation of various energy efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP's Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP's Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers' individual efficiency projects' energy savings. The CPP has achieved over 608 GWhs of energy savings since 2007. In mid-2024 CPP will be rebranded as Business Offerings for Sustainable Solutions (BOSS). The new program will also offer electrification incentives for space/water heating end uses.

Commercial Lighting Incentive Program. The Commercial Lighting Incentive Program ("CLIP") offers customers incentives to install newly purchased and installed energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (kW). CLIP's calculated savings approach allows customers to tailor their lighting efficiency upgrades to meet their lighting needs better, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 803 GWhs of energy savings since 2000.

Commercial Direct Install Program. The Commercial Direct Install ("CDI") Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less; CDI has achieved 511 GWhs of energy savings since its inception in 2008.

Home Energy Improvement Program. The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading/retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the neediest customers.

Refrigerator Exchange Program. The Refrigerator Exchange Program ("REP") is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities, multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third party contractor, ARCA (Appliance Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 106 GWhs since 2007.

LED Streetlight Program. The LED streetlight program provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this model is being expanded with a new $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

Program Analysis and Development Program. The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio, which are not included in individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California. Since the results of the studies, the Department has been crafting incentives for customers to electrify building end uses leveraging existing program delivery mechanisms to promote electric space and water heating, cooking and drying that have traditionally used natural gas as a fuel. While building electrification presents an opportunity to produce additional revenue, the Department's activities have been focused on promoting measures that effectively result in net utility bill reduction (inclusive of gas and electricity). This is directed towards maintaining a high level of customer benefit and satisfaction.

The Department has also partnered with the NREL to develop a technology prioritization tool as the Department ramps up its technology assessment efforts in the Emerging Technologies program. The tool helps prioritize the most impactful technologies that would improve energy efficiency for customers. These technology assessment efforts in the Emerging Technologies program incorporate many of the tools and methods used in the LA100 Study. See "THE POWER SYSTEM – LA100 Study" above.

The set of tools and methods used in the LA100 Study allows the Department to assess potential impacts as it relates to an emerging technology using the development of the building demand modeling that includes baseline consumption and characteristics data for residential and commercial building stock. This effort will analyze multiple use cases to empower the Department to provide more accurate potential studies and develop a pipeline of new technology assessments to determine the appropriate intervention required to get maximum benefits. The goal is to quantify achievable contributions towards goals set by State and local energy policies for the lowest cost.

From 2000 through December 2023, the Department has spent approximately $1.7 billion on its energy efficiency programs, and these programs are estimated to have reduced long-term peak period demand and consumption by approximately 970 MW and resulted in approximately 5,673 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers are estimated to have saved approximately 328 GWhs incrementally for the Fiscal Year 2022-23, falling short of energy savings targets by 89 GWhs. The Department spent approximately $138 million on energy efficiency programs for Fiscal Year 2022-23 of its approximately projected $190 million budgeted amount for such Fiscal Year. The Department will continue to evaluate the delivery and implementation of energy efficiency measures that support system reliability and resiliency while enabling customers to manage their power better. The Department anticipates increasing its expenditures for energy efficiency and building electrification programs in future years, based on portfolio planning utilizing the results of the Department's energy efficiency and building electrification potential studies.

Fuel Supply for Department-Owned Generating Units and Apex Power Project

Natural gas is used to fuel 100% of the Los Angeles Basin Stations. The Department's fossil fuel requirements for the Los Angeles Basin Stations to meet the electric load requirements of its customers in the City (referred to as "native load") were 64 billion equivalent cubic feet of natural gas during Fiscal Year 2022-23. In addition, the Department's fossil fuel requirements for the Apex Power Project were 18 billion equivalent cubic feet of natural gas during Fiscal Year 2022-23. In the early 2000s, the Department determined that acquiring natural gas reserves was advantageous, reasonable and prudent to ensure stable, long-term natural gas supplies to help meet future power generation demands. In June 2005, the Department, the Turlock Irrigation District and SCPPA (acting on behalf of its member California cities of Anaheim, Burbank, Colton, Glendale and Pasadena) acquired rights in natural gas-producing properties from the Anschutz Pinedale Corporation. Under the acquisition agreement, the Department obtained an approximately 74.5% ownership interest in a $300 million acquisition of leases of gas-producing property in Sublette County, Wyoming. This acquisition provided approximately 2.01% of the Department's average daily natural gas requirements for Fiscal Year 2022-23. No increase to this natural gas-producing program is expected at this time, however further capital investment in such program will be re-evaluated if market conditions change and the price of natural gas rises.

The Department obtains its remaining natural gas requirements through a competitively bid spot purchase program or through forward physical gas purchases for a specified period of time. The price of natural gas delivered into Southern California has fluctuated over the past few years and the Department expects prices to continue to fluctuate. To mitigate the effects of natural gas price volatility, the Department includes as part of the Electric Rates certain pass-through cost adjustments that provide recovery of natural gas and other fuel costs. See "ELECTRIC RATES – Rate Setting." In addition, the City Council enacted an ordinance to authorize the Department to enter into financial hedge contracts with respect to natural gas purchases to stabilize fuel costs for native load. See “Note (8) Derivative Instruments” of the Department’s Power System Financial Statements. Under this ordinance, the Department’s General Manager also may enter into biogas supply agreements for a period not to exceed ten years, so long as certain conditions are met. The use of natural gas swaps, derivatives and other price hedging arrangements are subject to risk management policies and review procedures established by the Board. The Department has developed a natural gas procurement strategy that includes a program of entering into financial hedges with various counterparties that have permitted terms of up to ten years and are intended to mitigate customer exposure to gas price volatility. The policy permits up to 75% of the Department’s natural gas requirements to be hedged through various measures (including such financial hedges), although the amount hedged in a given year may vary.

As of December 31, 2023, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2028-29 with an aggregate notional amount of approximately 86.2 million MMBtus. These financial hedges cover up to approximately 41% of the Department’s natural gas requirements based on the latest budget for the Fiscal Years through 2028-29. Tables describing the notional amount for each Fiscal Year and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with such hedges as of June 30, 2023 and 2022, can be found in Note (8).

The Department has previously used a physical delivery natural gas hedge program that was designed to hedge up to 50% of its forecasted usage. However, due to the limitation of gas injections at the SoCalGas Aliso Canyon storage facility, there is some uncertainty about intrastate gas transmission capacity available for electric generators. Consequently, the Department reduced the amount of forward physical gas purchased and limited the term of forward purchases based on the Department’s quarterly term plan forecasting periods.

The Department has firm interstate natural gas transportation capacity on the Kern River Pipeline System. The total amount of capacity is sufficient to transport 92% of the average amount of natural gas needed for the Los Angeles Basin Stations under current Department forecasts. Additional interstate pipeline capacity, if needed, is acquired through federally-approved capacity brokering programs or through gas purchases bundled with interstate transportation delivered into the SoCalGas intrastate system.

Intrastate transportation and balancing services are provided to the Department by SoCalGas sufficient to meet 100% of the Los Angeles Basin Stations’ requirements under SoCalGas’s Basic Transportation Service program (“BTS”). This enables the Department to deliver Kern River Pipeline System gas to the BTS receipt points in the State.

As of December 31, 2023, approximately 39% and 38% of the Department’s projected natural gas needs have been hedged for Fiscal Year 2024-25 and Fiscal Year 2025-26, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2028-29, approximately 2% of projected natural gas needs are hedged. The Department typically hedges a higher percentage of its natural gas needs as the operating year approaches. The goal of the current natural gas hedging program is to hedge up to five years forward from the current Fiscal Year, with the next Fiscal Year hedged up to 50% and the fifth Fiscal Year hedged up to 10%. The Department periodically reviews the goals of its natural gas hedging program.

The SoCalGas Aliso Canyon underground natural gas storage facility in the Porter Ranch area of Los Angeles leaked between October 23, 2015 and February 18, 2016 and was ordered to cease its injections by State agencies until testing of all operating wells has been completed. The volume in this storage field, SoCalGas’s largest, was reduced for safety reasons to a maximum of only 41 billion cubic feet (“BCF”), from its design maximum of 86 BCF. Although the required safety inspections are ongoing, the CPUC has allowed limited operation at Aliso Canyon to maintain gas pipeline and bulk electric system operational reliability. In August 2019, the CPUC approved a revision of the Aliso Canyon Withdrawal Protocol, removing the designation of “facility of last resort,” allowing SoCalGas more flexibility to withdraw from the storage field to maintain pipeline integrity. Since this change in policy, SoCalGas has been able to withdraw from the storage field more freely, thus reducing the volatility in both the volume of locally available natural gas and local natural gas pricing. In August 2023, the CPUC approved an increase in the allowable storage at the facility to 68.6 BCF.

There have been no localized natural gas curtailments impacting the Department and there have been no impacts to the Department from SoCalGas operations thus far. With the CPUC's August 31, 2023 vote to increase the Aliso Canyon interim storage limit, the agency also ended SoCalGas's need to comply with the Aliso Canyon Withdrawal Protocol as part of the implementation of that decision. In reaching its August decision, the CPUC determined that "restrictions on Aliso Canyon contributed to last year's natural gas price spikes and that removal of the Commission's storage level limitation provides a significant tool to mitigate future gas price spikes. To effectively implement this decision, the [CPUC] Energy Division is removing the Withdrawal Protocol to allow customers increased flexibility to use Aliso Canyon to moderate gas and electricity prices."

Water Supply for Department-Owned Generating Units

Water required for the operation of generating stations owned by the Department is secured from a number of sources. The Harbor Generating Station, Haynes Generating Station and Scattergood Generating Station use Pacific Ocean water for power plant cooling purposes. However, the Department is undertaking a long-term program of replacing the coastal generating units to eliminate the use of ocean water at these three locations in part to meet requirements of the SWRCB and the City's plans to eliminate the future use of once-through-cooling for these plants and replace them with clean energy alternatives. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station."* The Valley Generating Station, which is located inland, utilizes recycled water for cooling.

Spot Purchases

The Department purchases energy from the Bonneville Power Administration ("BPA") and other Pacific Northwest utilities under short-term "spot" arrangements to be delivered over the Pacific DC Intertie. For further information on the Pacific DC Intertie, see "– Transmission and Distribution Facilities – *Pacific DC Intertie and Sylmar Converter Station*." These purchases are used by the Department in conjunction with other resources for Power System operation. In addition, purchases of energy are made from other entities located in the Southwest. Spot purchases have generally been made at prices that permit economical operation of the Power System and that are comparable to the Department's costs for producing power from its own resources.

The availability of economical energy on the spot market has fluctuated greatly in recent years. Historically, the Department has not been dependent on such purchases to meet its customers' requirements. Although the Department currently continues to find economical spot purchase opportunities (including some for renewable energy), it cannot predict the future availability of power from either the Pacific Northwest or the Southwest for purchases at prices below the Department's costs for producing power from its own resources. The Department has increased its volume activity with the Cal ISO, including the purchase and sale of energy, as well as providing ancillary services, when excess capacity exists on its system.

Cogeneration and Distributed Generation

Currently thermal cogeneration installed in the Department's service area consists primarily of cogeneration projects of industrial and commercial customers. This totals approximately 322 MW nameplate capacity. Some cogeneration projects sell excess energy to the Department under interconnection agreements.

Distributed generation (the generation of electricity at or near the point of use) within the Department's service area currently consists primarily of cogeneration projects at customer facilities. Distributed generation also includes smaller generating units such as solar photovoltaic cells, fuel cells, micro-turbines and other smaller combustion engines. The Department manages a new technology demonstration program to assess the viability of some of these technologies. The Department also supports the development of new technologies through customer incentive programs. See "– Renewable Power Initiatives" and "– Energy Efficiency." These technology advancements may change the nature of energy generation and delivery and may materially affect the operating and financial position of the Department. For example, behind-the-meter resources such as cogeneration, demand response, and energy efficiency may have the effect of reducing customer demand, potentially diminishing revenue for the Department. On the other hand, if such resources are able to be successfully deployed during peak demand hours, this could reduce the Department's need to procure additional utility-scale resources to meet that peak demand.

Excess Capacity

The Department uses its extensive transmission network to sell excess generating capacity into the California, Northwest and Southwest energy markets. Net income from those sales is used to reduce costs to the Department's retail customers (primarily by applying revenues to the costs of capital improvements or toward an electric rate stabilization account in the Incremental Electric Rate Ordinance). With equipment outages, retirement of equipment, anticipated load growth and changes in GHG regulations which impact emission allowances, the Department anticipates that revenue from excess energy sales will be less certain than in the past. Wholesale revenues, as shown in "SELECTED FINANCIAL INFORMATION" under "OPERATING AND FINANCIAL INFORMATION – Financial Information," have accounted for less than 2% of overall Power System revenues in recent years.

Transmission and Distribution Facilities

Electricity from the Department's power generation sources is delivered to customers over a complex transmission and distribution system. To deliver energy from generating plants to customers, the Department owns and/or operates over approximately 15,000 miles of alternating current ("AC") and direct current ("DC") transmission and distribution circuits operating at voltage classes ranging from 120 volts to 500 kV, of which over approximately 11,000 miles are above ground. In addition to using its transmission system to deliver electricity from its power generation resources, under the OATT the Department transmits energy for others through such system when surplus transmission capacity is available and such transmission is permitted by the Master Resolution. As the operating agent of the Pacific DC Intertie, the Southern Transmission System, the Mead-Adelanto Transmission Project and certain Navajo-McCullough transmission facilities (all such facilities being described below), the Department, at the direction of and for the benefit of the respective co-owners/participants, transmits energy for the co-owners of, or participants in, these facilities.

Pursuant to AB 1890, signed into law on January 1, 1997, as part of the deregulation of the State electric industry, municipal utilities such as the Department were encouraged, but not required, to transfer operational control of their electric transmission facilities to the Cal ISO. The Department owns and operates in excess of 25% of the transmission facilities in the State. While the Department has not transferred operational control of its transmission facilities to the Cal ISO, the Department interacts with the Cal ISO on a regular basis. The Department serves as the scheduling coordinator for the delivery of that portion of the Department's energy that requires use of any part of the Cal ISO grid. The Department also coordinates with the Cal ISO with respect to some lines that are jointly owned by the Department and others. The Department is responsible for the costs associated with its use of the Cal ISO grid. The Department is registered as a participant in wholesale transactions in the Cal ISO market.

On April 1, 2021, the Department began participating in Cal ISO's Western EIM. The Western EIM is a real-time energy market that provides sub-hourly dispatch of participating resources for balancing supply and demand every five minutes, using the least-cost energy. As a Western EIM participant, the Department voluntarily provides excess energy capacity for dispatching to other participating utilities, while maintaining control of its generation assets and ratemaking authority. The Western EIM also provides an opportunity for the Department to purchase low-cost excess energy. The Department is participating voluntarily in order to tap into resources across a larger geographic area that includes eleven western states and the Canadian Province of British Columbia. Through its participation, the Department has experienced benefits from purchasing low cost energy during periods of high generation from renewables, a reduction in GHG emissions, as well as financial benefits from selling energy to the market during periods of low supply and higher prices. This helps lower the cost of delivery of power to its customers, and foster integration of renewable energy.

Legislation considered from time to time by the U.S. Congress and the State could potentially increase the level of jurisdictional control over the generation, transmission and distribution assets that comprise the Department's Power System and could encourage voluntary participation by the Department in a regional transmission organization. The City opposes any participation in a regional transmission organization that would be mandatory. The Department monitors any potential restrictions regarding control of transmission rates, authority to finance the Power System using bonds and use of the Power System to deliver electric power to the City.

Certain transmission facilities available to the Department are discussed below.

Southern Transmission System. The Southern Transmission System (the "STS") is an approximately 490-mile, ±500 kV DC transmission line from the Intermountain Generating Station, near Delta, Utah, to Adelanto, California, together with an AC/DC converter station at each end of the line. The STS is owned by IPA and is one of three major components of the IPP. See "– Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*." After the completion of an upgrade to its capacity in December 2010, a maximum of 2,400 MW can be transmitted over the STS. The Department's entitlement in the capacity of the STS is currently approximately 1,428 MW and is expected to increase to 2,172 MW in 2027 as a result of the Department increasing its share of the STS to 90.5% in accordance with the IPP Renewal Power Sales Contract. IPA is undertaking an approximately $2.7 billion renewal project to refurbish or replace the existing Adelanto Converter Station and Intermountain Converter Station with new HVDC stations on available land adjacent to the existing converter stations at Adelanto and IPP, which replacement components are currently scheduled for commercial operation from May 2024 through April 2028. The new converter stations will tie into the existing AC switchyards and connect to the existing DC transmission line. The schedule and cost estimate for the STS renewal project reflect design changes authorized by the IPA board of directors in November 2023 to facilitate an increase in the capacity of the STS from 2,400 to 3,000 MW to be undertaken in the future. The Department entered into a transmission service contract with SCPPA in 1983 to define the terms for transmission service on a "take-or-pay" basis for the Department's 59.5% entitlement right to capacity in the STS that it assigned to SCPPA in order for SCPPA to incur indebtedness sufficient to generate funds to finance the original construction of the STS. This service provides for the transmission of energy from the Intermountain Converter Station to the Adelanto Converter Station until 2027. The Department has negotiated a renewal transmission service contract with SCPPA for the same purpose as the original transmission service contract on a "take-or-pay" basis to allow SCPPA to be able to continue handling financings of the STS (including financing for costs of the ongoing upgrades to the Switchyard and converter station replacements) for the remainder of the term of the Department's participation in the IPP until 2077. SCPPA has issued bonds to finance a portion of the costs of the STS renewal project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Northern Transmission System. The Northern Transmission System (the "NTS") includes two approximately 50-mile, 345 kV AC transmission lines from IPP to the Mona Substation in Northern Utah, and one approximately 144-mile, 230 kV AC transmission line from IPP to the Gonder Substation in Nevada. The NTS was constructed for the delivery of power from IPP to certain municipalities in Utah and certain cooperative purchasers. Capacity on the NTS is available to the Department through the IPP Excess Power Sales Agreement. The Department can have up to a maximum NTS share allocation of 43.141% of the total capacity depending on the generation deemed excess by the 29 Utah municipalities and cooperatives that have access to such power. The capacity from IPP to Mona is 1,400 MW; the capacity from Mona to IPP is 1,200 MW; the capacity from IPP to Gonder is 200 MW; and the capacity from Gonder to IPP is 117 MW.

Pacific DC Intertie and Sylmar Converter Station. The Pacific DC Intertie is an approximately 846-mile, ±500 kV DC transmission system that connects Southern California to the hydroelectric and wind generation resources of the Pacific Northwest. A maximum of 3,210 MW can be transmitted over the entire Pacific DC Intertie System. The Department owns a 40% interest in the southern portion of the Pacific DC Intertie from the Nevada-Oregon border to its southern terminus at the Sylmar Converter Station in Sylmar, California and is the operating agent of the southern portion of the Pacific DC Intertie. The northern portion of the Pacific DC Intertie is owned and operated by BPA and extends from the Nevada-Oregon border to BPA's Celilo Station in The Dalles, Oregon.

Devers-Palo Verde Transmission Line. The Devers-Palo Verde Transmission Line is an approximately 250-mile, 500 kV AC line owned by Edison that connects the PVNGS with the Devers Substation outside Desert Hot Springs, California. As part of an exchange agreement, the Department purchases up to 368 MW of bi-directional firm transmission service on the Devers-Palo Verde Transmission Line from Edison (the "Devers-Palo Verde Agreement") at the rate being charged by the Cal ISO for that same service. The Devers-Palo Verde transmission path now consists of the Devers-Colorado River and Colorado River-Palo Verde transmission lines. The Department has the right to terminate the service upon 12 months written notice.

Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission project is an approximately 259-mile, 500 kV AC transmission line which originates at the Westwing substation in Phoenix, Arizona, connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace substation nearby. The Mead-Phoenix Transmission Project is currently owned by SCPPA, APS, Salt River Project, Western and Startrans IO, L.L.C. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Phoenix Transmission Project for the benefit of the Department through the purchase of the M-S-R Public Power Agency ("M-S-R") ownership share (11.5385% of the Westwing-Mead component and 8.09930% of the Mead-Marketplace component) of the Mead-Phoenix Transmission Project. After such acquisition, the Department's share is 57.732% of SCPPA's member-related interests in the Westwing-Mead component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 29.8462% of the entire Westwing-Mead component of the Mead-Phoenix Transmission Project) and 39.6459% of SCPPA's member-related interests in the Mead-Marketplace component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 30.5075% of the entire Mead-Marketplace component of the Mead-Phoenix Transmission Project). A maximum of 1,923 MW can be transmitted over the Westwing-Mead component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 332 MW. A maximum of 2,600 MW can be transmitted over the Mead-Marketplace component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 315 MW. The Department's average share of the Mead-Phoenix Transmission Project components is 50.39% of SCPPA's member-related interests in the Mead-Phoenix Transmission Project. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Phoenix Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Phoenix Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Phoenix Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project is an approximately 202-mile, 500 kV AC transmission line between the Adelanto substation, near Victorville, California and the Marketplace substation, near Boulder City, Nevada. The Mead-Adelanto Transmission Project was constructed by its owners, currently, SCPPA, Western and Startrans IO, L.L.C., in connection with the Mead-Phoenix Transmission Project. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Adelanto Transmission Project for the benefit of the Department through the purchase of M-S-R's 17.5% ownership share of the Mead-Adelanto Transmission Project. After such acquisition, the Department's share is 48.878% of SCPPA's member-related interests of the Mead-Adelanto Transmission Project (SCPPA's member-related interests comprise 85.4167% of the entire Mead-Adelanto Transmission Project). A maximum of 1,291 MW can be transmitted over the Mead-Adelanto Transmission Project, of which the Department has an entitlement share of 539 MW. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Adelanto Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Adelanto Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Adelanto Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Navajo-McCullough Transmission Line. The Navajo-McCullough Transmission Line is a 274-mile, 500 kV AC transmission line that originates at the Navajo Project near Page, Arizona, connects through the Crystal Substation near Las Vegas, Nevada and terminates at the McCullough substation, near Boulder City, Nevada. The Department owns 48.9% of the Navajo-McCullough Transmission Line, which was constructed as a part of the now-retired Navajo Generating Station. The Crystal Substation was constructed by NV Energy. NV Energy owns 100% of the Crystal Substation on behalf and for the benefit of the Navajo Project, including the Department.

Eldorado Transmission System. The Eldorado Transmission System's major components are the 59-mile, 500 kV AC Mohave-Eldorado transmission line, the 500 kV Mohave Switchyard, the Eldorado substation, which is comprised of a 220 kV switchyard and a 500 kV switchyard, and two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines. Pursuant to a Co-Tenancy and Operating Agreement, the Department is a 30% co-owner of the Mohave Switchyard, a 29.3% co-owner of the 500 kV switchyard, an 11.3% owner of the 220 kV switchyard, and a 15.1% co-owner of the transformers between the 500 kV and 220 kV switchyards, each of which is a part of the Eldorado Substation. The Department's ownership represents 716 MW of capacity on the Mohave-Eldorado transmission line and 215 MW of capacity on the two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines.

Barren Ridge Renewable Transmission Project. The Barren Ridge Renewable Transmission Project involved the expansion of the Barren Ridge Switching Station in order to increase the 3,119 MVA transmission capacity of renewable energy flowing into the Los Angeles Basin from generating facilities in Owens Valley, Kern County and the Tehachapi Mountains by 2,000 MVA.

Projected Capital Improvements

The Department has developed a series of Power System resource plans with each plan updating and refining the previous plan. The plans are developed in conjunction with the Department's strategic planning to meet its goals of continuing to provide reliable service to customers, maintaining a competitive price for the Power System's services and providing environmental leadership. Such resource plans act as guidance for the Department in implementing more specific short-term and long-term financial plans.

Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten-year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department achieved its energy efficiency goal of 15% energy efficiency savings by 2020 and is now focused on an additional 3,431 GWhs of energy savings by 2035. Enhancement and expansion of electric transmission resources will enable access to renewable energy resources. Certain in-basin energy projects will assist in integrating intermittent renewable resources into the Power System. Capital investments in the transmission and distribution system, including new business service and electric feeder lines, are required to support future growth. New control and monitoring systems are needed to continue to provide reliable and secure system operations. See " – Power System Reliability Program" below.

Power System Reliability Program. A significant power outage in 2006 caused the Department to conduct an evaluation of its electrical infrastructure and led to the development of a comprehensive distribution-focused power reliability program initially referred to as the "Power Reliability Program" with the following major components: (a) mitigation of problem circuits and stations based on the types of outages specific to the facility, including among other things, timely, permanent repairs of distribution circuits after a failure and fixing poorly performing circuits, (b) proactive maintenance and capital improvements that take into account system load growth and the inspections and routine maintenance that must take place to identify problems before they occur, (c) replacement cycles at the facilities that are in alignment with the equipment's life cycle such as replacing aging underground cables, overhead poles and circuits and substation equipment and (d) replacement of overloaded transformers. In 2013, another evaluation was completed and the program was expanded and renamed the "Power System Reliability Program." The Power System Reliability Program assesses all Power System assets affecting reliability in an integrated and comprehensive manner and proposes corrective actions as well as capital expenditures designed to minimize future outages and maintain reliability in the short and long term. The Power System Reliability Program includes the establishment of metrics and indices to help prioritize infrastructure replacement and expenditures for all major functions of the Power System, including distribution, transmission, generation, and substations. The Power System Reliability Program has been and is anticipated to be updated on an annual basis to adjust to varying Power System conditions and resource allocations.

Projected Capital Expenditures. As indicated in the table on the following page, for Fiscal Year 2023-24 through Fiscal Year 2027-28, the Department expects to invest approximately $13.5 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2023
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$1,926
IT Infrastructure*	553
Energy Efficiency	972
Power System Reliability Program	5,479
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	2,752
Power System Resource Plan	7
Shared Services: Facilities, Customer Services, Fleet	1,842
Total Power System Capital Improvements	$13,531

* For planning purposes, the power financial plan includes a proposed IT Cost Adjustment Factor (ITCAF) with an effective date of July 1, 2024. This proposed ITCAF is designed to recover the information technology (IT) expenses related to enterprise resource planning, smart grid, cybersecurity, and cloud infrastructure programs. These IT expenses include both capital and operation and maintenance expenses that are being allocated among base revenue supported categories such as operating support, infrastructure and other pass-through supported categories.

Source: Department of Water and Power of the City of Los Angeles.

The table below indicates, for Fiscal Year 2023-24 through Fiscal Year 2027-28, the expected funding sources for the capital improvements to the Power System expected for such Fiscal Years.

EXPECTED FUNDING SOURCES FOR CAPITAL IMPROVEMENTS
TO THE POWER SYSTEM
(in Millions)

Fiscal Year Ending (June 30)	**Internally Generated Funds**	**External/Debt Financing**	**Total Capital Expenditures[(1)]**
2024	$1,745	$ 422	$2,167
2025	869	1,697	2,566
2026	1,133	1,144	2,277
2027	1,350	1,479	2,829
2028	1,217	2,475	3,692
	$6,314	$7,217	$13,531

Source: Department of Water and Power of the City of Los Angeles.
(1) Net of reimbursements to the Department.
Note: Total may not equal sum of parts due to rounding.

The particular programs and commitments for capital improvements to the Power System are subject to review by Department stakeholders and others. The estimated costs of, and the projected schedule for, the expected capital improvements to the Power System and the Department's other capital projects are subject to a number of uncertainties. The ability of the Department to complete such capital improvements may be adversely affected by various factors including: (i) estimating errors, (ii) design and engineering errors, (iii) changes to the scope of the projects, (iv) delays in contract awards, (v) material and/or labor shortages, (vi) unforeseen site conditions, (vii) adverse weather conditions, (viii) contractor defaults, (ix) labor disputes, (x) unanticipated levels of inflation, (xi) environmental issues, (xii) the ability to access the capital markets at particular times and (xiii) delays in approvals of rate increases. No assurance can be given that the proposed projects will not cost more than the current budget for these projects. Any schedule delays or cost increases could result in the need to issue additional obligations and may result in increased costs to the Department. All payments of project costs associated with projected capital improvements are subject to Board approval.

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OPERATING AND FINANCIAL INFORMATION

The Department's service area consists of the City, where over 1.5 million customers are served, and certain areas of Inyo and Mono Counties in the State, where approximately 5,213 customers are served. As of December 31, 2023, 33% of the Power System's total energy sales (measured in MWhs) were to residential customers, 64% to commercial and industrial customers and the remaining 3% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately 34%, 61%, and 5% of total revenue, respectively.

Summary of Operations

The table below provides certain operating information with respect to the Power System.

POWER SYSTEM
SELECTED OPERATING INFORMATION
(Unaudited)

Operating Statistics	Six Month Period Ended December 31		Fiscal Year Ended June 30				
	2023[1]	2022	2023	2022	2021	2020	2019
Net Energy Load[2]	12,313	13,218	23,859	23,997	23,797	24,096	25,046
Net Hourly Peak Demand (MW)	5,453	6,216	6,216	4,911	6,106	5,637	6,201
Annual Load Factor (%)	51.12	48.14	43.81	55.79	44.49	48.66	46.11
Electric Energy Generation, Purchases and Interchanges[2]							
Generation[3][4]	8,885	9,360	17,172	17,194	17,281	17,947	16,862
Purchases[2]	4,385	5,313	9,148	9,440	8,988	7,295	8,966
Miscellaneous Energy Receipts[2]	–	–	–	–	705	470	230
Total Energy[2]	13,270	14,673	26,320	26,634	26,974	25,712	26,058
Less:							
Miscellaneous Energy Deliveries[2][5]	266	230	426	511	–	–	–
Losses and System Uses[2]	1,296	1,339	2,386	2,595	4,479	3,879	3,507
On-System Sales[2]	11,708	13,104	23,508	23,528	22,495	21,833	22,550
Sales of Energy[2]							
Residential	3,845	4,345	7,736	7,383	7,707	7,218	7,303
Commercial and Industrial	7,302	7,504	13,959	14,092	13,220	14,030	14,661
All Other	301	1,018	1,722	1,891	2,087	1,050	626
Total	11,448	12,867	23,417	23,366	23,014	22,298	22,590
Number of Customers – (Average, in thousands):							
Residential	1,448	1,434	1,440	1,430	1,414	1,405	1,397
Commercial and Industrial	128	128	128	128	126	126	126
All Other	7	7	7	7	7	7	7
Total	1,583	1,569	1,575	1,565	1,547	1,538	1,529

Source: Department of Water and Power of the City of Los Angeles.

(1) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(2) Thousands of MWhs.

(3) Does not include energy generated at Hoover Power Plant for plant use and for the use of the Bureau of Reclamation and the cities of Boulder City, Nevada; Burbank, California; Glendale, California and Pasadena, California.

(4) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.

(5) Deliveries include transmission loss energy paybacks and control area inadvertent interchange.

Financial Information

The tables below provide certain financial information with respect to the Power System.

POWER SYSTEM
SELECTED FINANCIAL INFORMATION
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31		Fiscal Year Ended June 30[1]				
	2023[2]	**2022**	**2023**	**2022**	**2021**	**2020**	**2019**
Operating Revenues							
Residential	$ 798,930	$ 880,847	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and Industrial	1,402,753	1,391,442	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale[3]	106,632	180,680	326,347	230,160	186,706	61,455	111,542
Other[4]	4,260	11,652	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$2,312,575	$2,464,621	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Average Revenue per kWh Sold[5]							
Residential	0.208	0.203	0.222	0.222	0.209	0.189	0.188
Commercial and Industrial	0.192	0.185	0.205	0.198	0.189	0.169	0.175
Average Annual Residential Usage[6]	3	3	5	5	5	5	5
Operating income	$ 317,206	$ 365,377	$ 742,176	$ 800,988	$ 744,139	$ 363,981	$ 512,310
As % of revenues	13.7%	14.8%	15.0%	17.4%	17.4%	9.6%	12.6%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[7]	$ 319,966	$ 377,130	$ 833,815	$ 532,290	$ 633,942	$ 320,065	$ 459,503
Adjusted Change in Net Position, including Power Transfer and accounting change[7]	$ 75,271	$ 145,087	$ 601,772	$ 307,275	$ 415,587	$ 90,152	$ 226,946

Source: Department of Water and Power of the City of Los Angeles.

(1) Derived from the Power System Financial Statements (except for usage statistics).

(2) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(3) Includes sales of power and transmission services to other utilities.

(4) Net of Uncollectible Accounts.

(5) The calculated Average Revenue per kWh Sold is based on dividing reported Operating Revenues by customer class by volumes for that customer class, including deferred revenues. The actual customer rates may differ from these calculated figures due to a variety of factors, including (1) demand and energy charges for commercial rates, (2) changes in usage between rate tiers within a customer class and between years, and (3) other factors including customer classification issues.

(6) MWh use per residential customer.

(7) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements. Adjustments reflect the impact of the implementation of new accounting standards, particularly GASB No. 75, which resulted in the recording of certain OPEB liabilities and a corresponding reduction in net position.

POWER SYSTEM
SUMMARY OF REVENUES, EXPENSES AND DEBT SERVICE COVERAGE
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31		Fiscal Year Ended June 30[(1)]				
	2023[(2)]	**2022**	**2023**	**2022**	**2021**	**2020**	**2019**
Operating Revenues							
Sales of Electric Energy:							
Residential	$ 798,930	$ 880,847	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and industrial	1,402,753	1,391,442	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale	106,632	180,680	326,347	230,160	186,706	61,455	111,542
Other[(3)]	4,260	11,652	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$2,312,575	$2,464,621	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Operating Expenses							
Production:							
Fuel for Generation	$ 197,839	$ 297,402	$ 435,524	$ 327,813	$ 228,697	$ 207,043	$ 296,506
Purchased Power	584,545	704,781	1,448,692	1,309,505	1,301,394	1,242,068	1,264,133
Energy Cost	782,384	1,002,183	1,884,216	1,637,318	1,530,091	1,449,111	1,560,639
Maintenance and Other Operating Expenses	822,356	724,113	1,570,429	1,430,993	1,323,158	1,364,303	1,412,750
Adjusted Operating Expenses[(4)(6)]	$1,604,740	$1,726,296	$3,454,645	$3,068,311	$2,853,249	$2,813,414	$2,973,389
Adjusted Operating Income[(4)(6)]	$ 707,835	$ 738,325	$1,503,894	$1,525,449	$1,415,229	$ 993,877	$1,097,541
Other non-operating income and expenses, net	172,527	168,987	413,808	1,482	145,303	268,502	239,211
Contributions in aid of construction	30,706	42,508	76,942	100,865	103,459	57,692	58,373
Adjusted Change in Net Position[(5)(6)]	$ 911,068	$ 949,820	$1,994,644	$1,627,796	$1,663,991	$1,320,071	$1,395,125
Debt Service							
Adjusted Interest[(6)(7)]	262,826	257,372	517,818	479,482	459,413	454,074	426,577
Principal	214,040	190,315	190,315	187,683	179,405	171,925	153,664
Total debt service	$ 476,866	$ 447,687	$ 708,133	$ 667,165	$ 638,818	$ 625,999	$ 580,241
Debt Service Coverage Ratio	N/A	N/A	2.82	2.44	2.60	2.11	2.40
Depreciation, amortization and accretion	$ 390,629	$ 372,948	$ 761,718	$ 724,461	$ 671,090	$ 629,896	$ 585,231
Transfers to the Reserve Fund of the City	$ 244,695	$ 232,043	$ 232,043	$ 225,015	$ 218,355	$ 229,913	$ 232,557

Source: Department of Water and Power of the City of Los Angeles.

(1) Derived from the Power System Financial Statements.

(2) Data for the six-month period ended December 31, 2023 is preliminary and subject to change. Results for the first six months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(3) Net of Uncollectible Accounts.

(4) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.

(5) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.

(6) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements.

(7) Interest expense excluding amortization of debt premium.

Indebtedness

*{update to come}*As of [February 1], 2024, approximately $[11.32]billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $[9.98] billion in principal amount is fixed-rate bonds and approximately $1.34 billion in principal amount is variable-rate bonds. In connection with the Department's five-year capital improvements to the Power System, the Department anticipates that it will issue approximately $7.2 billion of debt through June 30, 2028 payable from the Power Revenue Fund. See "THE POWER SYSTEM – Projected Capital Improvements" and "Note (9) Long-Term Debt" of the Department's Power System Financial Statements.

Certain of the Department's outstanding debt are "federally subsidized direct-pay" bonds, for which, instead of the interest being tax-exempt, the Department receives a subsidy payment from the Treasury Department equal to 35% of the interest paid or up to 70% of the tax credit rate determined by the Treasury Department, depending on the type of federally subsidized direct-pay bonds. Pursuant to certain federal budget legislation adopted in August 2011, starting as of March 1, 2013, the government's subsidy payments were reduced as part of a government-wide "sequestration" of many program expenditures. The amount of the reduction of the subsidy payment has ranged from a high of 8.7% in 2013 to a low of 5.7% for federal fiscal years 2021 through 2031. The amount of this reduction for the Power System has been less than $1.5 million annually and such reductions are presently scheduled to continue through September 30, 2031.

Congress can terminate, extend, or otherwise modify reductions in subsidy payments due to sequestration at any time. In addition, under the Statutory Pay-As-You-Go Act of 2010, an increase in the federal deficit caused by a new tax or entitlement spending law could trigger further sequestration reductions to non-exempt mandatory spending programs, absent a waiver either as part of the triggering law or in subsequent legislation. If the sequestration reduction rate were to increase to 100%, the reduction in subsidy payments for the Power System would currently be approximately $[25.5] million annually. *{update to come}*

On May 25, 2023, the Department entered into a revolving credit agreement (the "Wells RCA") with Wells Fargo Bank, National Association ("Wells Fargo") in a principal amount not-to-exceed $300 million outstanding at any one time; provided that the Department can request that Wells Fargo increase the available commitment under the Wells RCA by an additional $200 million, with approval of such increase being at the sole discretion of Wells Fargo. As of [February 1], 2024, the Department has no obligations outstanding under the Wells RCA payable from the Power Revenue Fund. As of [February 1], 2024, the Department had $[50] million principal amount outstanding under the Wells RCA payable from the Water Revenue Fund. Under the Wells RCA, which expires on May 22, 2026, amounts due may be paid by the Department at any time at its option and in the event of default under the Wells RCA, amounts outstanding would be due immediately. The Department expects to pay principal amounts due under the Wells RCA payable from the Power Revenue Fund from proceeds of subsequent borrowings or from reserves available to the Power System. Amounts borrowed under the Wells RCA payable from the Power Revenue Fund are considered Parity Obligations under the Master Resolution. The Department does not believe that its obligations with respect to the Wells RCA will result in a default under the Department's other Parity Obligations.

For more information about the Department's variable rate bonds, including their associated liquidity facilities (as applicable), see "Note (10) Variable Rate Bonds" of the Department's Power System Financial Statements.

In addition, as of [February 1], 2024, the Department was obligated on a "take-or-pay" basis under power purchase or transmission capacity contracts for debt service payments (its share representing approximately $[2.46] billion principal amount of bonds) and for operating and maintenance costs of the related projects. The Department has entered into, and may in the future enter into additional, "take-or-pay" contracts in connection with renewable energy projects and other projects undertaken by the joint powers agencies in which it participates. The Department's obligations to make payments under such "take-or-pay" contracts are unconditional payment obligations. See "– Take-or-Pay Obligations" for the "take-or-pay" contracts the

Department has entered as of [February 1], 2024. All such commercial paper and "take-or-pay" contract obligations rank on a parity with the Department's Bonds as to payment from the Power Revenue Fund.

Take-or-Pay Obligations

The Department entered into the IPP Contract and the IPP Excess Power Sales Agreement to purchase up to a 66.79% share of the output of the IPP. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*." The Department is also a member of SCPPA and participates in a number of SCPPA projects, including a number of renewable energy projects. See "THE POWER SYSTEM – Renewable Power Initiatives." The Department's obligations to make payments with respect to the IPP and the SCPPA projects in which it participates are unconditional "take-or-pay" payment obligations, obligating the Department to make such payments as operating expenses of the Power System whether or not the applicable project is operating or operable, or the output thereof is suspended, interfered with, reduced, curtailed or terminated in whole or in part. The IPP Contract, the IPP Excess Power Sales Agreement and the agreements with respect to the SCPPA projects (other than with respect to projects in which the Department is the sole participant) contain certain step-up provisions obligating the Department to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs related to the project and reserves as a result of a defaulting participant. The Department's participation and share of bond debt service obligation (without giving effect to any provisions requiring the Department to contribute to any deficiencies upon default by another participant) as of [February 1], 2024, for each of the foregoing projects are shown in the following table:

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POWER SYSTEM
TAKE-OR-PAY OBLIGATIONS FOR BONDS
As of [February 1], 2024
(Dollars in Millions) ***{update to come}***
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt[6]
Intermountain Power Agency			
IPP	$ 102[1]	48.62%[2]	$ 49[1]
IPP (Renewal Project)	1,531	71.44	1,093
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	16	100.00[3]	16
Mead-Phoenix Transmission Project	13	100.00[3]	13
Linden Wind Energy Project	75	100.00[4]	75
Milford Wind Corridor Phase I Project	76	92.50[5]	70
Milford Wind Corridor Phase II Project	66	100.00[4]	66
Southern Transmission System (STS)	126	59.50[5]	75
STS (Renewal Project)	677	90.50[5]	613
Windy Point Project	162	100.00[4]	162
Apex Power Project	230	100.00[5]	230
Total	$3,074		$2,462

Source: Department of Water and Power of the City of Los Angeles.

(1) Represents a portion of the IPP and SCPPA debt issued to finance costs of the IPP repowering project and STS renewal project, the Department's share of the bond debt service obligation for which is payable in accordance with the terms of, and the Department's participant share under, the IPP Contract prior to the effective date of the Renewal Power Sales Contract in June 2027. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(2) Includes the Department's obligations under the IPP Contract (48.617%) but does not include the Department's obligations under the IPP Excess Power Sales Agreement as described under the caption "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(3) The bonds remaining outstanding relate to the additional interest acquired by SCPPA solely for the benefit of the Department.

(4) Equals the Department's share of SCPPA's and the City of Glendale's entitlements. See "THE POWER SYSTEM – Renewable Power Initiatives."

(5) Equals the Department's share of SCPPA's entitlement.

(6) In addition to outstanding principal, the Department is obligated to pay its share of interest on outstanding debt and annual operating and maintenance costs. See Note (5) in the Department's Power System Financial Statements for additional information.

FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY

The following regulatory programs affect the Department and the electric utility industry and should be considered when evaluating the Department and considering an investment in the bonds. The Department cannot predict at this time whether any additional legislation or rules will be enacted which will affect the Power System's operations, and if such laws or rules are enacted, what the costs to the Department might be in the future because of such action. See "GENERAL," "ELECTRIC RATES," "THE POWER SYSTEM – Projected Capital Improvements," "OPERATING AND FINANCIAL INFORMATION" and the Department's Power System Financial Statements for additional information relating to the Department.

California Climate Change Policy Developments

State regulatory agencies such as CARB and the CEC are pursuing a number of regulatory programs designed to reduce GHG emissions and encourage or mandate renewable energy generation. The following is a summary of certain programs. See also "Environmental Regulation and Permitting Factors" below.

GHG Regulations. In September 2006, the Global Warming Solutions Act was signed into law. This law established the State's target to reduce Statewide GHG emissions back to 1990 levels by 2020, which represented a reduction of approximately 25% Statewide. In September 2016, SB 32, an amendment to the Global Warming Solutions Act, was signed into law, and established a new target to reduce Statewide GHG emissions 40% below 1990 levels by 2030. In September 2022, AB 1279, the California Climate Crisis Act, was signed into law. AB 1279 establishes a State policy to achieve net zero GHG emissions as soon as possible, but no later than 2045, to achieve and maintain net negative GHG emissions thereafter, and to ensure that by 2045, Statewide anthropogenic GHG emission are reduced to at least 85% below the 1990 levels.

CARB implemented the Global Warming Solutions Act through regulations (the "Cap-and-Trade Regulations") that imposed a declining economy-wide limit or cap on GHG emissions from major sources within the State, including the electricity generation industry, and allocates the aggregate emissions limit through the distribution of allowances, or emission credits.

The Cap-and-Trade Regulations require all regulated entities, including the Department, to report annual GHG emissions and to obtain and surrender GHG emission allowances and/or offsets for each metric ton of GHG emissions. Cap-and-trade compliance covers GHG emissions from in-state fossil-fueled power plants, as well as imported electricity from out-of-state resources such as the IPP. In addition, the Department may indirectly bear compliance costs for purchased electricity.

The Department, like other electric utilities, receives an administrative allocation of allowances to cover its expected GHG emissions. Entities that emit GHGs at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or from other covered entities with surplus allowances. The Department believes that, if its administrative allowance allocation is not sufficient to cover GHG emissions from all of the Department's generation and purchases of electricity to serve retail customer load, the Department could obtain additional allowances by participating in the CARB auctions or the secondary market. The Department also believes that the cost of compliance with the Cap-and-Trade Regulations for retail customer load will be substantially covered by the administrative allocation of allowances and/or existing rate adjustments and anticipated rate increases through 2030. When the Department sells electricity in the wholesale market, it is required to purchase allowances to cover GHG emissions for those wholesale electricity sales, and the cost of such allowances is included in the electricity price paid by the wholesale buyer.

In July 2017, CARB adopted amendments to the Cap-and-Trade Regulations, which included a 40% reduction in the Statewide GHG emissions cap between 2021 and 2030. CARB granted administrative allowance allocations to electrical distribution utilities such as the Department for the 2021 to 2030 compliance period. The Power System is expected to be able to continue to comply with these amendments with minimal impact to its finances or operations in connection with the implementation of the Power System's resource plan.

In July 2017, AB 398 was signed into law to extend the State's Cap-and-Trade Regulations from 2021 to 2030. The bill cleared both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, CARB was directed to address the following: establish a price ceiling, offer non-tradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance overallocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. AB 398 was passed in conjunction with two companion bills: AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities, and Assembly Constitutional

Amendment No. 1 ("ACA-1"), which created a special Greenhouse Gas Reduction Reserve Fund in the State Treasury, into which all new money collected from the auction of cap-and-trade allowances is to be deposited beginning January 1, 2024 until the effective date of legislation that appropriates money from the fund. The money is then to be appropriated to the existing Greenhouse Gas Reduction Fund, from which money is allocated to 75 California Climate Investment programs administered by 23 State agencies to reduce GHG emission and provide environmental, economic, and public health benefits. A minimum of 35% of California Climate Investments are required to benefit priority populations including disadvantaged communities and low-income communities and households.

In December 2018, CARB approved amendments to the Cap-and-Trade Regulations to make the cap-and-trade program consistent with AB 398 requirements. The amendments to the Cap-and-Trade Regulations went into effect on April 1, 2019. The Department does not expect that its continued compliance with these amendments will have a material adverse effect on the operations or financial condition of the Power System.

In February 2023, CARB issued a market notice regarding further updates to the Cap-and-Trade Regulations. Topics to be considered include banked allowances, evaluation of the program caps within the context of the 2022 Scoping Plan goals, conducting electricity sector and industrial sector leakage studies, updates to offset protocols, addressing the new Extended Day Ahead Market for electricity, protecting low-income households from disproportionate impacts of energy prices, and carbon dioxide sequestration and removal projects developed under the SB 905 Carbon Capture, Removal, Utilization, and Storage Program. CARB has indicated the proposed rule amendments package is expected to be posted for public review and comment in early to mid-2024. *{update to come}*

GHG Emissions Performance Standard and Financial Commitment Limits. Pursuant to SB 1368 (Chapter 598, Statutes of 2006), the CEC adopted a GHG emissions performance standard ("EPS") for electric generating facilities of 1,100 pounds of CO_2 per MWh for "covered procurements" by POUs, such as the Department. SB 1368 also prohibits POUs from making any "long-term financial commitment" in connection with "baseload generation" that does not satisfy the EPS. Generally, a "long-term financial commitment" is any new or renewed power purchase agreement with a term of five years or more, the purchase of an interest in a new power plant or any investment, other than routine maintenance, in an existing power plant that is designed and intended to extend the life of the plant by more than five years or results in an increase of 50 MW or more in its rated capacity. "Baseload generation" means a power plant that is intended to operate at an annualized capacity factor of 60% or more.

California Renewable Portfolio Standard. The State's legislature and executive branch have been active in promoting increasingly stringent renewable energy procurement requirements since 2002. Early efforts established a standard of 20% of renewable electricity generation by 2017. Since then, both legislative and executive branch initiatives have raised that standard in multiple phases.

In April 2011, SBX 1-2, the California Renewable Energy Resources Act, was signed into law. SBX 1-2 established procurement targets for three compliance periods ("Compliance Periods 1 through 3") to be implemented by the procurement plan: 20% of the utility's retail sales were to be procured from eligible renewable energy resources by December 31, 2013; 25% by December 31, 2016; and 33% by December 31, 2020. The Department met the targets established by SBX 1-2 for each of Compliance Periods 1 through 3.

In October 2015, SB 350 was signed into law, which requires retail sellers and POUs, such as the Department, to make reasonable progress each year to ensure it achieves 40% of retail sales from eligible renewable energy resources by December 31, 2024, 45% of retail sales from eligible renewable energy resources by December 31, 2027, and 50% of retail sales from eligible renewable energy resources by December 31, 2030.

In September 2018, SB 100 was signed into law, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as the Department, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of the State that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to State end-use customers by December 31, 2045. Defining resources that constitute a "zero-carbon resources" will be subject to further regulatory proceedings of the CEC and CARB. The CEC has adopted updates to the RPS Enforcement Procedures for Publicly Owned Utilities which incorporate requirements set forth in SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350 pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of RPS procurement must be from contracts of 10 years or more in duration or in ownership or ownership agreements. The updated regulations became effective on July 12, 2021.

In September 2022, SB 1020 was signed into law SB 1020, which revised the policy of the State established by SB 100 to provide that eligible renewable energy resources and "zero-carbon resources" supply 90% of all retail sales of electricity to State end-use customers by December 31, 2035, 95% by December 31, 2040, 100% by December 31, 2045, and 100% of electricity procured to serve all State agencies by December 31, 2035.

See "THE POWER SYSTEM – Renewable Power Initiatives" and "– Projected Capital Improvements" for a description of the Department's existing and potential renewable energy projects.

Biomass Legislation. In September 2016, SB 859 was signed into law. Among other things, SB 859 required certain electric utilities to enter into five-year contracts for at least 125 MW of biomass capacity with facilities that generate energy from feedstock harvested from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. Due to the specific requirements of the law, the available facilities satisfying the requirements of the law are limited. The Department, SCPPA and the other POUs procured biomass capacity under contracts from two projects to satisfy the SB 859 requirements: (i) the ARP-Loyalton contract that ended in April 2023, from which the Department's contracted amount was 8.9 MW, and (ii) a contract for 5.4 MW of capacity with Roseburg Forrest Products Co., in Weed, California. See "THE POWER SYSTEM – Renewable Power Initiatives – *Biomass Development*."

Energy Storage Legislation. In October 2017, SB 801 was signed into law, which required the Department, by June 1, 2018, to determine the cost-effectiveness and feasibility of deploying a minimum aggregate total of 100 MW of cost-effective energy storage solutions to help address the Los Angeles Basin's electrical system operational limitations resulting from reduced gas deliverability from the Aliso Canyon natural gas storage facility. Department staff performed analysis and found that a 100 MW battery energy storage system paired with solar generation at the grid would be cost effective by 2022. See "THE POWER SYSTEM – Renewable Power Initiatives – *Energy Storage Development*." To comply with such legislation, the Department has entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2.

Renewable Energy Policy Development. In August 2018, the CEC adopted the policy "Toward A Clean Energy Future, 2018 Integrated Energy Policy Report Update" (the "2018 IEPR"). The 2018 IEPR is composed of two volumes. The first volume is a high-level summary of the energy policies the State has implemented in recent years. This high-level summary includes (i) the State's participation in an international pact to reduce emissions and increase renewable electricity procurement to 33% by 2020 and 50% by 2030; (ii) continued support for incentives or mandates for more homes and business to install rooftop solar; (iii) an executive order calling for at least five million zero-emission vehicles on the State's roads by 2030 and an extensive expansion of charging and refueling infrastructure; and (iv) continued support for the development and implementation of an energy efficient program in existing buildings. The second volume provides updated analysis of issues raised in previous Integrated Energy Policy Reports, including "advancing then-Governor Brown's call to expand state adaptation activities through Executive Order B-30-15, with the goal of making the consideration of climate change a routine part of planning," as well as, "enhancing the resiliency of the electricity system while integrating increasing amounts of renewable energy." See "– Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board*" below.

Legislation and Court Action Relating to Wildfires. In September 2016, SB 1028 was signed into law. SB 1028 requires each POU, including the Department, each IOU and each electric cooperative in the State to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 required the governing board of each POU to make an initial determination of whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on historical fires and local conditions. POU governing boards were required to independently make this determination based on all relevant information, including the CPUC's Fire Threat Map which was adopted by the CPUC in January 2018 (discussed below). On September 5, 2018, the Board determined that the Power System's overhead electrical lines and equipment do not pose a significant risk of causing a catastrophic wildfire. Prior to the enactment of SB 1028, the Department has had an active fire prevention plan since 2008, which includes construction standards, a vegetation management program, and an inspection and maintenance program.

SB 901, which was signed into law in September 2018, amends certain provisions of SB 1028. Under SB 901, among other things, POUs, such as the Department, are required to prepare a wildfire mitigation plan, initially before January 1, 2020, and annually thereafter. SB 901 requires the POU to contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator is to be made available to the public and presented at a public meeting of the POU's governing board. Consistent with the requirements of SB 901 and subsequent legislation (AB 1054 discussed below), the Department updates its wildfire mitigation plan on an annual basis, with comprehensive revisions and independent evaluator reviews occurring every three years.

In 2017, the CPUC adopted a work plan for the development and adoption of the CPUC Fire-Threat Map. On the CPUC Fire-Threat Map, any area in a Tier 2 fire-threat area is depicted as an "elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires" and any area in a Tier 3 fire-threat area is depicted as an "extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." Based on the Department's wildfire mitigation plan dated June 2023, approximately 13.8% of the Power System's overhead distribution power lines fall within a Tier 2 area and approximately 0.5% of the Power System's overhead distribution power lines fall within a Tier 3 area. The Department has not modeled a total destruction scenario in Tier 2 and Tier 3 areas of its service territory because such areas represent a small portion of the Power System's service territory; but the Department believes that based on the low density of the property in the applicable Tier 2 and Tier 3 areas, the potential property damage is expected to be relatively low. In these applicable Tier 2 and Tier 3 areas, the Department continues to replace wooden pole assets with alternative material poles, install covered conductors where feasible, equip poles for high wind load in order to resist fire damage, and employ a robust vegetation management program to further mitigate wildfire risk exposure.

AB 1054 was signed into law by Governor Newsom in July 2019. AB 1054 requires POUs to submit their wildfire mitigation plans for annual review to a newly created California Wildfire Safety Advisory Board (the "CWSAB"), with comprehensive revisions submitted every three years. The Department continues to submit its wildfire mitigation plan to the CWSAB on an annual basis, with the last submittal occurring on June 28, 2023. The Department's 2023 wildfire mitigation plan represents a comprehensive update, meeting the requirements of AB 1054. On December 4, 2023, the CWSAB published its guidance advisory opinion for the recently submitted wildfire mitigation plans. The CWSAB's advisory opinion to each POU was to embark on a collaborative approach as set forth in the advisory opinion designed to improve POU reporting on its wildfire prevention efforts and the CWSAB's ability to comprehend and advise on those reports. Previous reviews by the CWSAB found the Department's wildfire mitigation plan to be comprehensive with clear descriptions of its relevant programs. The Department is actively engaging with the ongoing CWSAB's meetings to discuss updates to POU wildfire mitigation plans. The Department is required to submit its next annual update to the Department's wildfire mitigation plan to the CWSAB by July 1, 2024.

AB 1054 also establishes a new wildfire fund for IOUs to pay for eligible, uninsured third-party damage claims arising from future covered wildfires. Participation in the wildfire fund is exclusive to IOUs. Each of the major IOUS in California are now participating in the Wildfire Fund. POUs, such as the Department, are not eligible to participate in or receive funding for wildfire claims from the Wildfire Fund

A number of wildfires occurred in the State in the last several years. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by such utilities' infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County*, No. S243247 (Cal. Aug. 15, 2019) involving damages related to sewage overflows from a city sewer system, the California Supreme Court issued a rare but narrow decision regarding inverse condemnation liability. The residential property owner in that case failed to install a mandatory sewer backflow device, allowing the court to conclude the absence of that device was the substantial cause of the damages to the residence. The property owner was unable to prove the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. SB 1028, SB 901 and AB 1054 do not address existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions address the State's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry, including the Department.

See "LITIGATION – Wildfire Litigation" for information about current litigation regarding wildfires and "THE DEPARTMENT – Insurance" for information about the Department's current insurance coverage for wildfires.

Environmental Regulation and Permitting Factors

General. Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions. The Department's four Los Angeles Basin power plants are subject to the Regional Clean Air Incentives Market ("RECLAIM") NOx regulations adopted by the SCAQMD. In accordance with these regulations, SCAQMD established annual NOx allocations for stationary source facilities based on historical emissions with a declining emissions cap. These allocations are in the form of RECLAIM trading credits ("RTCs"). Facilities can comply with RECLAIM by purchasing RTCs from the RECLAIM market, installing emission controls, and/or reducing operations. The Department has installed emission control equipment at its power plants to reduce NOx emissions. The Los Angeles Basin Stations are all equipped with emission control equipment. As a result of the installation of NOx control equipment and the modernization of existing electric generating units, the Department has had sufficient RTCs to meet its native load requirements for normal operations under the NOx RECLAIM regulation.

In March 2017, the SCAQMD adopted the 2016 Air Quality Management Plan and included a control measure to achieve an additional five tons per day NOx reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology ("BARCT") as soon as feasible.

In July 2017, AB 617 was signed into law, which addresses criteria pollutants (including NOx) and toxic air contaminants at stationary sources. RECLAIM facilities are subject to the BARCT requirements of AB 617.

The market-based RECLAIM program is being transitioned to a command-and-control regulatory structure. The RECLAIM program was originally scheduled to end on December 31, 2023 but is now expected to extend past 2025 after the EPA's approval of the State Implementation Plan and the resolution of outstanding issues with the New Source Review ("NSR") Program. The Los Angeles Basin Stations will transition from RECLAIM to a source-specific NOx rule for electric generating units that will include NOx limits reflecting BARCT. SCAQMD Rule 1135, the "command-and-control" rule for electric generating units, was adopted in November 2018. Instead of receiving an annual allocation of emission credits, electric generating units will be required to meet a NOx emission limit. The NOx emission limit for simple cycle gas turbines is 2.5 parts per million ("ppm") while the NOx emission limit for combined cycle gas turbines is 2.0 ppm. Failure to meet the NOx limits by the December 31, 2023 compliance date would prohibit out-of-compliance generating units from operating. To comply with the new NOx limit of 2.5 ppm for simple cycle gas turbines, the existing selective catalytic reduction equipment for the Department's simple cycle combustion turbines at the Harbor Generating Station and the Valley Generating Station were tuned. To meet the 2.0 ppm limit for combined cycle gas turbines, the combustors of combined cycle combustion turbines at the Harbor Generating Station are being upgraded. The upgrade of the Harbor Generating Station's combined cycle combustors is still in progress. The Harbor Generating Station's combined cycle unit is currently offline and is expected to be in compliance with the Rule 1135 NOx emission limit upon returning to service. The Department does not expect the modifications to have a material adverse effect on the operations or financial condition of the Power System. The remaining electric generating units at the Los Angeles Basin Stations either already meet the NOx limits or are exempt from the rule. On January 7, 2022, Rule 1135 was amended to reference startup and shutdown provisions as defined in SCAQMD Rule 429.2, which establishes requirements during startup and shutdown and exempts units regulated under Rule 1135 from NOx emission limits during startup and shutdown.

Regulatory Actions Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates GHG emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, GHGs are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies to control emissions from the new or modified stationary source. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. GHGs from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

In May 2023, the EPA proposed new carbon pollution standards for coal and natural gas-fired power plants. The proposed rule would establish CO_2 emissions limits and guidelines for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines. The proposal includes the following elements, in each case reflecting the application of best systems for emissions reduction ("BSER"), taking into account costs, energy requirements and other statutory factors: (i) strengthening the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establishing emission guidelines for carbon pollution from existing fossil fuel-fired steam generating units (including coal, oil and natural gas-fired units) beginning January 1, 2030; and (iii) establishing emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired) beginning January 1, 2032 or January 1, 2035, depending on which BSER technology is pursued. Under the proposed rule, emissions standards are established for different subcategories of power plants according to unit characteristics such as their capacity, their intended length of operation, and/or their frequency of operation. The proposed rule would generally require more CO_2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO_2 requirements over time. The standards are based on emission control methods that can be installed at the plants, including technologies such as carbon capture and sequestration/storage, low-GHG hydrogen co-firing, and natural gas co-firing; however, the determination of whether to implement such technologies or to comply with the proposed emissions limits by other means would be made by power plant operators and state regulators. Under the proposal, states would be required to submit compliance plans to the EPA within 24 months of the effective date of the adoption of the regulations. The EPA requested public comment on the proposed regulation. The Department submitted comments and will continue to participate in the rulemaking process. There can be no assurance that the final regulations to be adopted after public comment will reflect the currently proposed standards or as to the timing of the adoption and implementation thereof.

See also "THE POWER SYSTEM – General," "– Department-Owned Generating Units," "– Jointly Owned Generating Units and Contracted Capacity Rights in Generating Units," "– Projected Capital Improvements," "– Energy Efficiency" and "– Renewable Power Initiatives."

Air Quality – Mercury. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants ("HAPs"), including mercury. In February 2012, the EPA finalized a rule called the Mercury and Air Toxics Standards ("MATS") to reduce emissions of toxic air pollutants, including mercury, from coal- and oil-fired electric generating units, and subsequently amended the rule in 2013 and 2014. The MATS rule set technology-based emission limitation standards for mercury and other toxic air pollutants, based upon reductions available through the use of "maximum achievable control technology" at coal- and oil-fired electric generating units. The rule has minimal impact to IPP, the one remaining coal-fired plant that is a source of energy for the Department. IPP did not have to install control technology and EPA has deemed the IPP units as low-emitting electric generating units ("LEEs"). IPP is subject to periodic testing, work practice standards and recordkeeping requirements.

The State of Utah adopted minimum performance criteria for existing electric generating units and offset requirements for potential increases in mercury emissions from new or modified electric generating units. Utah's minimum performance criteria include a rule, effective January 1, 2012, that coal-fired power plants, such as IPP, meet a mercury emissions limit of 0.00000065 lb/MMBtu or have at least a 90% mercury removal efficiency. IPP complies with the Utah mercury standard.

In April 2023, the EPA published its proposed rule entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review." The proposed rule establishes a lower mercury emissions standard for lignite coal, which does not apply to IPP. The rule also proposes to reduce the emissions standard for filterable particulate matter ("fPM") from 0.03 lb/MMBtu to 0.01 lb/MMBtu. In addition, it requires the owners and operators of existing coal-fired plants to only use a continuous emissions monitoring system ("CEMS") to demonstrate compliance with the new fPM standards. The EPA requested comments on the proposed rule, as well as on the possibility of reducing the compliance timeframe from three years to one year from the effective date. IPP submitted a comment letter. The final rule is expected to be published in Spring 2024. *{update to come}*

SCAQMD Air Quality Management Plan. The SCAQMD periodically prepares an overall plan, known as an Air Quality Management Plan (the "AQMP"), which include control measures to meet federal air quality standards and incorporate the latest technical planning information. The AQMP is a regional and multi-agency effort. In 2021, the Department participated in the stakeholder working group meetings dedicated to the development of the 2022 AQMP and the rules and rule amendments to implement the control measures included in the 2022 AQMP that could potentially impact the Department's operations. In December 2, 2022, the SCAQMD Board approved the 2022 AQMP, which aims for a 45% reduction in NOx emissions through this plan. In January 2023, CARB adopted the SCAQMD 2022 AQMP, and directed staff to submit the 2022 AQMP to the EPA as a revision to the California State Implementation Plan to achieve the federal air quality standard for ozone. As called for in the 2022 AQMP, SCAQMD has initiated separate rulemaking processes addressing the different proposed control measures cited in the AQMP, which are ongoing.

Water Quality – Cooling Water Process.

General. A cooling process is necessary for nearly every type of steam turbine electrical generating station. Once-through-cooling is the process where water is drawn from a source, pumped through equipment at a power plant to provide cooling and then discharged. In once-through-cooling, the water is not chemically changed in the cooling process; however, the water temperature can increase. The water drawn into the intake and the thermal discharges are regulated by the federal Clean Water Act and similar state law.

EPA Requirements. A final regulation implementing Section 316(b) of the Clean Water Act ("Rule 316(b)") addresses the impacts of water intake by once-through-cooling systems. Rule 316(b) affects intake structures for power generating facilities that withdraw more than two million gallons per day for cooling purposes. The Department has determined it will comply with impingement mortality ("IM") and entrainment mortality ("EM") by replacing once-through-cooling with other technology by the deadline of 2029 negotiated with the SWRCB.

State Water Resources Control Board. The SWRCB established a separate statewide policy with respect to the Clean Water Act Section 316(b) in 2010 published as Section 2922 of Title 23 of the California Code of Regulations ("Regulation Section 2922"). The regulation generally requires all facilities subject to the Clean Water Act Section 316(b) to either use closed cycle cooling or flow reduction commensurate to that of wet closed cycle. The Department owns three coastal generating stations that utilize once-through-cooling, that provide approximately 85% of the Department's in-basin generation and 39% of the total generating plant capacity owned by the Department, which are subject to Regulation Section 2922.

In July 2011, the SWRCB adopted an amendment to Regulation Section 2922 that accelerated the compliance dates for three coastal units and extended the compliance dates until 2024 for two coastal units and 2029 for the remaining four coastal units. In August 2023, the SWRCB adopted another amendment, extending the compliance date for the two units with a December 31, 2024 deadline to December 31, 2029. The new compliance schedule allows for both grid reliability and a financially sustainable path forward while making the equipment upgrades necessary to remove the coastal generating stations' units from utilizing once-through-cooling, shifting the focus from repowering to clean energy alternatives.

Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station. The SWRCB's Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bay and Estuaries of California (the "California Thermal Plan") has different thermal criteria for discharges into estuaries and bays than it does for discharges into the ocean. The water discharges from Harbor Generating Station and Haynes Generating Station were originally permitted as ocean discharges. In January 2003, however, the Los Angeles Regional Water Quality Control Board ("LARWQCB") informed the Department that it (i) reclassified the Harbor Generating Station discharge as an enclosed bay discharge and that (ii) it intends to reclassify the Haynes Generating Station discharge as an estuary discharge during the next permit renewal. The Harbor Generating Station NPDES permit was renewed by the LARWQCB in July 2003, with the new enclosed bay classification and the associated, more stringent, permit limits. Based on the notice of intent to reclassify the Haynes Generating Station discharge and planned changes to be made to the Haynes Generating Station's flow volume, the Department has completed a hydrological model of the Lower San Gabriel River. Haynes discharges into the San Gabriel River, which in turn flows into the ocean. The hydrological study concluded that the estuary classification does not reflect current site conditions with the operation of the existing power plants. However, the LARWQCB stated that for regulatory purposes, the Lower San Gabriel River would likely represent an estuary. With this designation, the Haynes Generating Station would be unable to comply with the California Thermal Plan and other permit conditions without a permit variance. If the Department is unable to obtain a permit variance, the Haynes Generating Station facility could be limited or unable to operate. The LARWQCB has recognized the need to continue utilizing once-through cooling at the Haynes Generating Station through 2029 for electric grid reliability and is currently working with the Department on a solution for all discharge issues associated with the estuary designation, which could include the issuance of a variance or time schedule order (TSO).

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, as well as State statutes, impose strict liability for cleanup costs upon those who generate or dispose of hazardous substances and hazardous wastes. The Department's past disposal practices may result in Superfund liability as previously approved disposal methods or sites become candidates for Superfund classification. In addition, under these statutes, the Department may be held liable for cleanup activities on property that it owns and operates, even if the conditions requiring cleanup existed before the Department's occupancy of a site. As a result, the Department may incur substantial, but presently unknown, costs as a participant in the cleanup of sites contaminated with hazardous substances or wastes.

Coal Combustion Residuals. In April 2015, the EPA promulgated the final coal combustion residuals ("CCR") rule, which regulates the disposal and management of CCRs as non-hazardous under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The final CCR rule became effective in October 2015.

Under the CCR rule, existing impoundments for managing CCR must either cease accepting CCR materials as of the rule's effective date, or implement a variety of measures to ensure that such facilities will not result in releases to the environment. One such requirement is that all such facilities be retrofitted with liners that are intended to prevent the migration to groundwater of contaminants found in CCR. In addition, the rule requires monitoring of groundwater to determine whether releases have occurred, and to contain or clean up any such releases that are discovered.

The IPP utilizes impoundments (ponds and landfills) for the management of CCR that are subject to the CCR rule. The IPP has met all interim compliance requirements for the new CCR rule including: setting up a public website and posting CCR operating records, developing new groundwater monitoring wells and sampling plans, beginning to sample groundwater wells quarterly, and developing and implementing a fugitive dust monitoring plan.

The Department believes that the IPP's CCR management facilities may not meet the design criteria required for surface impoundments and that releases of certain contaminants have occurred from the current, unlined impoundments. The Department understands that IPA has made notification that IPP will cease operations of the coal-fired boilers and switch to another fuel source for generation by 2028.

The Department has estimated the IPP's total cost of compliance with the final CCR rule to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period commencing in 2019 and ending between approximately 2025 and 2028 (except for long-term monitoring and maintenance, which would last approximately 30 years after closure). Of this total cost, the Power System would be responsible for a percentage equal to its total use of energy produced by IPP. For more information about IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

In November 2019, the EPA proposed revisions (Part A) to the CCR rule. The proposed revisions focus on closure requirements for impoundments and landfills. IPA is opting to comply with the alternate closure requirement as currently described in the current CCR rule. The proposed revisions include additional requirements to get approval of the EPA or the state to close impoundments in accordance with alternate closure procedures. There is also a new requirement to prepare a plan to mitigate potential risk to human health and environmental from CCR surface impoundments. The Part A revisions were finalized and published in the Federal Register in August 2020. IPP has submitted a request to the EPA demonstrating that they meet the alternate closure procedures as described in the regulations. IPP is awaiting EPA review and approval which was initially expected to be received by April 2021; [however, as of ______ 2024, the EPA has not yet made a determination on IPP's demonstration submission]. *{update to come}*

In February 2020, the EPA proposed a federal CCR permit program. Currently, the CCR rule is self-implementing and is enforced primarily though citizen suits which are decided in federal district courts. This program will not change the provisions of the regulations but the EPA will be able to review, approve, issue, and enforce the CCR regulations through the permit program.

In March 2020, the EPA proposed more revisions (Part B) to the CCR rule including provisions to demonstrate equivalent alternate liners, using CCR for closing impoundments, and completion of closure by removal during post closure care period. The proposed revisions do not impact IPA's plan to follow alternate closure requirements.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects resulting from exposure to electric and magnetic fields created by high voltage transmission and distribution equipment. Additional studies are being conducted to determine the relationship between electric and magnetic fields and certain adverse health effects, if any. At this time, it is not possible to predict the extent of the costs and other impacts, if any, which the electric and magnetic fields concerns may have on electric utilities, including the Department.

For additional information regarding environmental matters, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Hoover Power Plant – Environmental Considerations" and " – Palo Verde Nuclear Generating Station – Nuclear Waste Storage and Disposal.*"

Energy Regulatory Factors

Developments in the California Energy Market. In the late 1990s, the State restructured its electricity market so that regulated retail suppliers were required to purchase their customers' supply needs through a centralized, wholesale market. During portions of 2000 and 2001, wholesale market prices in the State became highly volatile. The volatility in wholesale prices that the State experienced in 2000 and 2001 was due to a number of factors, including flaws in the structure of the wholesale market and unlawful manipulation of the wholesale market. As discussed below, the wholesale market in the State has since been redesigned, and Congress has established mechanics for policing wholesale markets.

Volatility in electricity prices in the State may nevertheless return due to a variety of factors that affect the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of GHG emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impact of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in the State and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). Volatility in electricity prices may contribute to greater volatility in the Power System's Power Revenue Fund from the sale (and purchase) of electric energy and, therefore, could materially affect the financial condition of the Power System. To mitigate price volatility and the Department's exposure on the spot market, the Department undertakes resource planning activities and plans for its resource needs. Of particular note, the Department has power supply contracts and other arrangements relating to its system supply of power that are of specified durations. See "THE POWER SYSTEM – Generation and Power Supply."

Energy Policy Act of 1992. The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in federal regulation of the electric utility industry, particularly in the area of transmission access under sections 211, 212 and 213 of the Federal Power Act, 16 U.S.C. § 791a et seq. The purpose of these changes, in part, was to bring about increased competition among wholesale suppliers. As amended, sections 211, 212 and 213 authorize FERC to compel a transmission provider to provide transmission service upon application by an electricity supplier. FERC's authority includes the authority to compel the enlargement of transmission capacity as necessary to provide the service. The service must be provided at rates, charges, terms and conditions that are set by FERC. Electric utilities that are owned by municipalities or other public agencies are "transmitting utilities" that may be subject to an order under sections 211, 212 and 213. EPAct 1992 prohibits FERC from requiring “retail wheeling” under which a retail customer that was located in one utility’s service area could obtain electricity from another source. An order by FERC to provide transmission might adversely affect the Power System by, and among other things, increasing the Department’s cost of owning and operating transmission facilities and/or by reducing the availability of the Department’s transmission resources for the Department’s own use.

Energy Policy Act of 2005. The Energy Policy Act of 2005 (“EPAct 2005”) addresses a wide array of matters that affect the entire electric utility industry, including the Department.

Subject to certain conditions and limitations, EPAct 2005 authorizes FERC to require an unregulated transmitting utility such as the Department to provide electric transmission services at rates that are comparable to those that the unregulated transmitting utility charges itself; and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. FERC may compel open access in this context unless the order would violate a private activity bond rule for purposes of section 141 of the Code (as defined below). To date, FERC has chosen to exercise its authority on a case-by-case approach. Additionally, FERC has the authority to require the provision of transmission services in response to specific requests for service. See ELECTRIC RATES – Rate Regulation. Furthermore, should the Department purchase transmission services from a public utility, as defined in the Federal Power Act, pursuant to the terms and conditions of FERC’s *pro forma* OATT, the *pro forma* OATT requires the Department to provide the transmission provider it is purchasing transmission services from, comparable transmission service that it is capable of providing on similar terms and conditions over facilities and for the transmission of electric energy.

EPAct 2005 provides for criminal penalties for manipulative energy trading practices.

EPAct 2005 repealed the Public Utility Holding Company Act of 1935, which prohibited certain mergers and consolidations involving electric utilities. EPAct 2005 gives FERC and state regulators access to books and records within holding companies that include regulated public utilities. In addition, FERC may oversee inter-affiliate transactions within such holding company systems. These provisions of EPAct 2005 are referred to as “PUHCA 2005.” PUHCA 2005 does not apply to the Department but generally accommodates more combinations of assets within the electric utility industry.

EPAct 2005 requires the creation of national and regional electric reliability organizations to establish and enforce, under FERC’s supervision, mandatory standards for the reliable operation of the bulk power system. The standards are designed to increase system reliability and to minimize blackouts. FERC has designated NERC as the national electric reliability organization. FERC has designated WECC as the regional reliability organization for utilities in the West, including the Department. Failure to comply with NERC and WECC standards exposes a utility such as the Department to penalties. NERC and WECC audit the Department’s compliance with the reliability standards once every three years and, as indicated above, impose penalties for non-compliance. The Department has from time to time fallen short in meeting its regulatory and reporting requirements on a timely basis and either has self-reported or responded to audit findings from WECC. The Department does not believe that pending reporting and audit matters will have a material adverse effect on the Department’s operations or financial position.

Under EPAct 2005, State IOUs were required to offer, to each of their classes of customers, a time-based rate schedule that would enable customers to manage their energy use through advanced metering and communications technology.

EPAct 2005 authorizes FERC to compel the siting of certain transmission lines if FERC determines that a state has unreasonably withheld approval.

EPAct 2005 promotes increased imports of liquefied natural gas and includes incentives to support the development of renewable energy technologies. EPAct 2005 also extends for 20 years the Price-Anderson Act, which provides certain protection from liability for nuclear power issues and provides incentives for the construction of new nuclear plants.

Future Regulation of the Electric Utility Industry. The electric utility industry is highly regulated and is also regularly subject to reform. The most recent reforms and proposals are aimed at reducing emissions of GHGs from combustion of fossil fuels and reducing impacts from using ocean water for power plant cooling. The Department is unable to predict future reforms to the electric utility industry or the ultimate impact on the Department of recent reforms and proposals. In particular, the Department is unable to predict the outcome of proposals on reducing GHG emissions and the associated impact on the operations and finances of the Power System or the electric utility industry.

Security of the Power System

The Department has a variety of physical security measures in place, as well as a cybersecurity program, aimed at protecting the assets of the Power System and the technological systems utilized in the delivery of electric power service to its customers. The Department operates a 24/7 operations center and regularly plans for emergency situations and develops response protocols.

Elements of the Department's cybersecurity program include ongoing monitoring, regular staff training and a robust defense-in-depth strategy, as well as other cybersecurity and operational safeguards such as performance of periodic security risk assessments and gap analyses to identify security strengths and vulnerabilities; practices for the backup and recovery of data; security awareness training, and response plans.

The Department also collaborates with federal and state partners and other public and private third parties to assess vulnerabilities, share information and actively detect and manage risks. However, there can be no assurance that any existing or additional safety and security measures will prove adequate in the event that cyberattacks or military conflicts or terrorist activities (including cyber terrorism) are directed against the Power System.

Attacks, especially zero-day exploits directed at critical electric sector operations could damage generation, transmission or distribution assets, cause operational malfunctions and outages, and result in costly recovery and remediation efforts. Further, cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period. United States government agencies have in the past issued warnings indicating that critical infrastructure sectors such as the electric grid may be specific targets of cybersecurity threats. The costs of security measures or of remedying physical and/or cybersecurity breaches could be material.

Global Health Emergencies; COVID-19 Pandemic

A pandemic, epidemic or outbreak of an infectious disease can have significant adverse health and financial impacts on global and local economies. For example, beginning in 2020, the COVID-19 pandemic negatively affected economic activity throughout the world, including the United States and the State of California. The initial impacts of stay-at home orders globally was unprecedented, with commerce, travel, asset values and financial markets experiencing disruptions worldwide. The COVID-19 pandemic impacted the Department in certain respects, however, there was not a material adverse impact to the Power System's operations or its ability to meet its financial obligations as a result of the COVID-19 pandemic. Certain employees of electric and water utility systems, like the Department, are considered essential workers and were exempt from the "stay at home" and "safer at home" orders issued by the State, the County and the City, and therefore, the Department continued to fully provide power and water services to its customers throughout the pandemic. In response to the COVID-19 outbreak, the Department implemented a number of temporary measures intended to mitigate operational and financial impacts to the Department, and to assist the Department's customers. In light of the measures taken by the Department to mitigate the economic impact of COVID-19 on its customers, including extended payment options and deferrals of disconnections of water and power services for non-payment, the Department has experienced and may continue to experience an increase in delinquent accounts and increase of uncollectible accounts. See "ELECTRIC RATES – Billings and Collections – *COVID-19 Effects*."

The declarations of the COVID-19 pandemic as a public health emergency have been lifted. However, future pandemics and other widespread public health emergencies can and do arise from time to time. No assurance can be given that the operations or finances of the Power System will not be negatively affected in the event that the pandemic and its consequences again become more severe or another national or localized outbreak of highly contagious or epidemic disease occurs in the future.

Changing Laws and Requirements

On both the state and federal levels, legislation is introduced frequently that would have the effect of further regulating environmental impacts relating to energy, including the generation of energy using conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cyber-security legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, and renewable energy incentives that could provide grants and credits to municipal utilities to invest in renewable energy infrastructure. Congress has also considered other bills relating to energy supplies and development.

The Department is unable to predict at this time whether any of these or other legislative proposals will be enacted into law and, if so, the impact they may have on the operations and finances of the Power System or on the electric utility industry in general.

In addition to state and federal legislation, citizen initiatives in the State can lead and have led to substantial restrictions upon governmental agencies, both in terms of raising revenue and management of governmental entities generally. Articles XIII C and XIII D of the State's constitution provided limits on the ability of governmental agencies to increase certain fees and charges. Such articles were adopted pursuant to measures qualified for the ballot pursuant to the State's constitutional initiative process.

In addition, from time to time other initiative measures could be adopted by State voters, which may place limitations on the ability of the Department to increase revenues.

See also "ELECTRIC RATES – Rate Setting – *Proposition 26*."

Other General Factors

The electric utility industry in general has been, or in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of many electric utilities, including the Department, and the level of utilization of generation and transmission facilities. Such factors (a number of which are further discussed elsewhere herein), include, among others:

- Effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements;

- Changes resulting from conservation and demand side management programs on the timing and use of energy;

- Effects on the integration and reliability of the power supply from the increased usage of renewables;

- Changes resulting from a national energy policy;

- Effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities and from competitive transmitting of less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity;

- The repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities;

- Increased competition from independent power producers and marketers, brokers and federal power marketing agencies;

- "Self-generation" or "distributed generation" (such as microturbines, fuel cells, and solar installations) by industrial and commercial customers and others;

- Issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission line service from transmission projects financed with outstanding tax-exempt obligations;

- Effects of inflation on the operating and maintenance costs of an electric utility and its facilities;

- Changes from projected future load requirements;

- Increases in costs and uncertain availability of capital;

- Shifts in the availability and relative costs of different fuels (including the cost of natural gas and coal);

- Financial difficulties, including bankruptcy, of fuel suppliers and/or renewable energy suppliers;

- Changes in the electric market structure for neighboring electric grids such as the EIM operated by the Cal ISO;

- Sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the State;

- Inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity;

- Other legislative changes, voter initiatives, referenda and statewide propositions;

- Effects of changes in the economy, population and demand of customers in the Department's service area;

- Effects of possible manipulation of the electric markets;

- Acts of terrorism or cyberterrorism;

- Impacts of climate change;

- The outbreak of another infectious disease such as the COVID-19 pandemic impacting the global, national or local economy or a utility's service area;

- Natural disasters or other physical calamities, including but not limited to, earthquakes, floods and wildfires, and potential liabilities of electric utilities in connection therewith;

- Adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk; and

- Legislation or court actions allowing City residents and/or businesses to purchase power from sources outside the Department.

Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility, including the Department.

Seismic Activity

The City and the Owens River and Mono Basin areas are located in regions of seismic activity. The principal earthquake fault in the Los Angeles area is the San Andreas Fault, which extends an estimated 700 miles from north of the San Francisco area to the Salton Sea. At its nearest point to the City, the San Andreas Fault is about 35 miles north of the Los Angeles Civic Center.

In March 2015, the Uniform California Earthquake Rupture Forecast (the "2015 Earthquake Forecast") was issued by the Working Group on California Earthquake Probabilities. Organizations sponsoring the Working Group on California Earthquake Probabilities include the U.S. Geological Survey, the California Geological Survey, the Southern California Earthquake Center and the California Earthquake Authority. According to the 2015 Earthquake Forecast, the probability of a magnitude 6.7 or larger earthquake over the next 30 years (from 2014) striking the greater Los Angeles area is 60%. From the Uniform California Earthquake Rupture Forecast published in April 2008 (the "2008 Earthquake Forecast"), the estimated rate of earthquakes around magnitude 6.7 or larger decreased by about 30%. However, the estimate for the likelihood that the State will experience a magnitude 8.0 or larger earthquake in the next 30 years (from 2014) increased from about 4.7% in the 2008 Earthquake Forecast to about 7.0% in the 2015 Earthquake Forecast. The 2015 Earthquake Forecast considered more than 250,000 different fault-based earthquakes, including multi-fault ruptures, whereas the 2008 Earthquake Forecast considered approximately 10,000 different fault-based earthquakes.

While it is impossible to accurately predict the cost or effect of a major earthquake on the Power System or to predict the effect of such an earthquake on the Department's ability to provide continued uninterrupted service to all parts of the Department's service area, there have been various studies conducted to assist the Department in assessing seismic risks. Based on these studies, the Department completed numerous projects designed to mitigate seismic risks and seismically strengthen Power System infrastructure and facilities. Projects include landslide repairs and bank replacements, the placement of spare transformers and the installation of generating peaking units at the Valley Generating Station and Haynes Generating Station to provide peaking capacity and the ability for generating units to go from a shutdown condition to an operating condition and start delivering power without assistance from the power grid. No studies have been conducted or commissioned by the Department outside of the State. See "GENERAL – Insurance."

LITIGATION

General

A number of claims and suits are pending against the Department or that directly affect the Department with respect to the Power System for alleged damages to persons and property and for other alleged liabilities arising out of its operations. Certain of these suits are described below. In the opinion of the Department, any ultimate liability which may arise from any of the pending claims and suits is not expected to materially impact the Power System's financial position, results of operations, or cash flows.

Wildfire Litigation

In recent years, there has been an increase in the number and the severity of wildfires in the State. Due to this increase of fire activity, there has been an increase in litigation filed against power utilities that own and operate generating stations, distribution lines, and transmission lines throughout the State. The Department is a named party in cases relating to the Creek fire, which ignited on December 5, 2017, and the Getty fire, which ignited on October 28, 2019. The Department denies liability for the ignition of the Creek fire. The unique set of facts regarding the ignition of the Getty fire likely creates Department liability; however, various defense theories and third party claims are being explored.

Creek Fire. Regarding the Creek fire, the Department has a number of cases pending in the Los Angeles Superior Court. The state court cases are brought by attorneys representing individual plaintiffs for alleged property damage and business losses. The cases have all been consolidated for litigation with a single judge. Edison is also a party in the state court cases, and is a focus of the fire ignition. Edison was named as a co-defendant by the individual plaintiff and insurance subrogation plaintiffs. Edison has filed an indemnity cross-complaint against the Department. All equitable allegations/comparative fault allegations would be part of the state court trial. On September 15, 2023, as a result of the court's ruling on a joint motion by the Department and Edison to dismiss certain plaintiff cases, approximately 370 individual plaintiff cases were dismissed, leaving approximately 90 individual plaintiff cases. The dismissals significantly reduce the Department's financial exposure for the wildfire.

If liability is found against the Department in connection with the Creek fire, an accurate exposure amount cannot now be estimated. However, the cumulative alleged damages in the pending state court cases, which now include only individual plaintiff cases and a reduced number of plaintiffs, is within the Department's insurance coverage for this matter. The Department has insurance coverage for this matter in the amount of $185 million with a $3 million self-insured retention.

Getty Fire. The Power System matters associated with the Getty fire currently involve multiple cases all alleging inverse condemnation and tort causes of action. The state court actions were filed on behalf of individual plaintiffs and insurance subrogation parties. The cases are pending in the Los Angeles Superior Court Complex Division with all cases ordered consolidated/related before a single judge.

Cross-complaints have been filed by the Department naming the adjacent property owner C&C Mountaingate, Inc., and Department tree vegetation contractor Utility Tree Service, LLC and its subcontractor, Tree Service Kings, Inc.

The court has set a September 18, 2024, trial date regarding only the inverse condemnation issue. At that time the court will determine if inverse condemnation applies, and if so, a later date will be set at which a jury will decide the amount of damages.

On or about October 16, 2023, the insurance subrogation plaintiffs and the Department reached a settlement of the insurance subrogation plaintiffs' claims for $36,786,657.50. The individual plaintiff cases remain.

The total financial exposure of the Getty fire cannot now be specifically determined. However, the cumulative damages presently alleged in the pending state court cases, which now include only individual plaintiff cases, is within the Department's insurance coverage for this matter. The Department has insurance coverage in the amount of $177.5 million with a $3 million self-insured retention for this matter. Despite not having done anything wrong, the Department could face financial liability claims due to the doctrine of inverse condemnation discussed above under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – Legislation and Court Action Relating to Wildfires."

For details regarding the extent of the Department's current insurance, see "GENERAL – Insurance." As discussed under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*," legislation addressing the State's inverse condemnation and "strict liability" issues for utilities in the context of wildfires in particular could have a significant effect on the electric utility industry, including the Department.

[Project Vote: PWP, BWP]

RESOLUTION NO. 2024-018

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APPROVING THE **REVISED** ANNUAL BUDGET FOR
AMERESCO CHIQUITA LANDFILL GAS PROJECT
FOR THE FISCAL YEAR
JULY 1, 2023 THROUGH JUNE 30, 2024

BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority (the "Authority") that:

1. The revised budget for the Ameresco Chiquita Landfill Gas Project for the Fiscal Year July 1, 2023 through June 30, 2024, submitted to this Board of Directors, is hereby approved. The Executive Director is hereby authorized and directed to place the revised budget so approved in final form, with such changes as shall be necessary or advisable to comply with the Ameresco Chiquita Landfill Gas Project Power Sales Contracts; and the revised budget hereby approved, in such final form, shall constitute the Authority's Annual Budget for Fiscal Year July 1, 2023 through June 30, 2024.

2. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 18th day of April 2024.

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PRESIDENT
Southern California Public
Power Authority

ATTEST:

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RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

ANNUAL BUDGET - REVISION 1

July 1, 2023 through June 30, 2024
Ameresco Chiquita Landfill Gas Project
($000)

Month	PPA Payments	Direct Admin. & General	Indirect Admin. & General	**Total Cost of Power**	Estimated Energy (MWH) to be Scheduled
Jul	$180	$1	$3	**$184**	2,765
Aug	$180	$1	$3	**$184**	2,765
Sep	$180	$1	$3	**$184**	2,765
Subtotal	$540	$3	$9	**$552**	8,296
Oct	$180	$1	$3	**$184**	2,765
Nov	$180	$1	$3	**$184**	2,765
Dec	$180	$1	$3	**$184**	2,765
Subtotal	$540	$3	$9	**$552**	8,296
Jan	$180	$1	$3	**$184**	2,765
Feb	$180	$1	$3	**$184**	0
Mar	$180	$1	$3	**$184**	0
Subtotal	$540	$3	$9	**$552**	2,765
Apr	$0	$1	$3	**$4**	0
May	$0	$1	$3	**$4**	0
Jun	$0	$1	$3	**$4**	0
Subtotal	$0	$3	$9	**$12**	0
Total FY	$1,620	$12	$36	**$1,668**	19,356

July 1, 2023 through June 30, 2024
Ameresco Chiquita Landfill Gas Project
($000)

	Revenues			Revenue Fund Disbursements		
Month	Monthly Power Costs	Interest Earnings (4)	Total Revenues	Operating Fund	Reserve Account	Total Revenue Fund Dis-bursements
Jul	$184	$0	$184	$184	$0	$184
Aug	$184	$0	$184	$184	$0	$184
Sep	$184	$0	$184	$184	$0	$184
Subtotal	$552	$0	$552	$552	$0	$552
Oct	$184	$0	$184	$184	$0	$184
Nov	$184	$0	$184	$184	$0	$184
Dec	$184	$0	$184	$184	$0	$184
Subtotal	$552	$0	$552	$552	$0	$552
Jan	$184	$0	$184	$184	$0	$184
Feb	$184	$0	$184	$184	$0	$184
Mar	$184	$0	$184	$184	$0	$184
Subtotal	$552	$0	$552	$552	$0	$552
Apr	$4	$0	$4	$4	$0	$4
May	$4	$0	$4	$4	$0	$4
Jun	$4	$0	$4	$4	$0	$4
Subtotal	$12	$0	$12	$12	$0	$12
Total FY	$1,668	$0	$1,668	$1,668	$0	$1,668

[Project Vote: LADWP, IID]

RESOLUTION NO. 2024-019

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APPROVING THE **REVISED** ANNUAL BUDGET FOR
HEBER 1 GEOTHERMAL PROJECT
FOR THE FISCAL YEAR
JULY 1, 2023 THROUGH JUNE 30, 2024

BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority (the "Authority") that:

1. The revised budget for the Heber 1 Geothermal Project for the Fiscal Year July 1, 2023 through June 30, 2024, submitted to this Board of Directors, is hereby approved. The Executive Director is hereby authorized and directed to place the revised budget so approved in final form, with such changes as shall be necessary or advisable to comply with the Heber 1 Geothermal Project Power Sales Contracts; and the revised budget hereby approved, in such final form, shall constitute the Authority's Annual Budget for Fiscal Year July 1, 2023 through June 30, 2024.

2. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 18th day of April, 2024.

____
PRESIDENT
Southern California Public
Power Authority

ATTEST:

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RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

ANNUAL BUDGET

July 1, 2023 through June 30, 2024
Heber 1 Geothermal Project - Revised
($000)

Month	PPA Payments	LADWP Project Manager	Direct Admin. & General	Indirect Admin. & General	Working Capital Reserve	**Total Cost of Power**	Estimated Energy (MWH) to be Scheduled
Jul	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Aug	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Sep	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Subtotal	$5,871	$9	$12	$36	$0	**$5,928**	66,124
Oct	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Nov	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Dec	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Subtotal	$5,871	$9	$12	$36	$0	**$5,928**	66,124
Jan	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Feb	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Mar	$1,957	$3	$4	$12	$0	**$1,976**	22,041
Subtotal	$5,871	$9	$12	$36	$0	**$5,928**	66,124
Apr	$1,957	$3	$4	$12	$0	**$1,976**	22,041
May	$3,889	$3	$4	$12	$0	**$3,908**	43,826
Jun	$3,889	$3	$4	$12	$0	**$3,908**	43,826
Subtotal	$9,735	$9	$12	$36	$0	**$9,792**	109,694
Total FY	$27,348	$36	$48	$144	$0	**$27,576**	308,066

July 1, 2023 through June 30, 2024
Heber 1 Geothermal Project - Revised
($000)

	Revenues				Revenue Fund Disbursements		
Month	Monthly Power Costs	Interest Earnings (4)	Total Revenues		Operating Fund	Reserve Account	Total Revenue Fund Dis-bursements
Jul	$1,976	$37	$2,013		$2,013	$0	$2,013
Aug	$1,976	$37	$2,013		$2,013	$0	$2,013
Sep	$1,976	$37	$2,013		$2,013	$0	$2,013
Subtotal	$5,928	$111	$6,039		$6,039	$0	$6,039
Oct	$1,976	$37	$2,013		$2,013	$0	$2,013
Nov	$1,976	$37	$2,013		$2,013	$0	$2,013
Dec	$1,976	$37	$2,013		$2,013	$0	$2,013
Subtotal	$5,928	$111	$6,039		$6,039	$0	$6,039
Jan	$1,976	$37	$2,013		$2,013	$0	$2,013
Feb	$1,976	$37	$2,013		$2,013	$0	$2,013
Mar	$1,976	$37	$2,013		$2,013	$0	$2,013
Subtotal	$5,928	$111	$6,039		$6,039	$0	$6,039
Apr	$1,976	$37	$2,013		$2,013	$0	$2,013
May	$3,908	$37	$3,945		$3,945	$0	$3,945
Jun	$3,908	$37	$3,945		$3,945	$0	$3,945
Subtotal	$9,792	$111	$9,903		$9,903	$0	$9,903
Total FY	$27,576	$444	$28,020		$28,020	$0	$28,020

[Project Vote: LADWP, GWP]

RESOLUTION NO. 2024-020

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APPROVING THE ANNUAL BUDGET FOR
ELAND SOLAR & STORAGE CENTER, PHASE I PROJECT
FOR THE FISCAL YEAR
JULY 1, 2023 THROUGH JUNE 30, 2024

BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority (the "Authority") that:

1. The budget for the Eland Solar & Storage Center, Phase I Project for the Fiscal Year July 1, 2023 through June 30, 2024, submitted to this Board of Directors, is hereby approved. The Executive Director is hereby authorized and directed to place the budget so approved in final form, with such changes as shall be necessary or advisable to comply with the Eland Solar & Storage Center, Phase I Project Power Sales Contracts; and the budget hereby approved, in such final form, shall constitute the Authority's Annual Budget for Fiscal Year July 1, 2023 through June 30, 2024.

2. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 18th day of April 2024.

____
PRESIDENT
Southern California Public
Power Authority

ATTEST:

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RANDOLPH KRAGER
ASSISTANT SECRETARY
Southern California Public
Power Authority

ANNUAL BUDGET

July 1, 2023 through June 30, 2024
Eland Solar 1 + Storage Project
($000)

Month	Test Energy Payments	PPA Payments	Project Manager	Working Capital	Direct Admin. & General	Indirect Admin. & General	**Total Cost of Power**	Estimated Energy (MWH) to be Scheduled
Jul	$0	$0	$0	$0	$0	$0	**$0**	0
Aug	$0	$0	$0	$0	$0	$0	**$0**	0
Sep	$0	$0	$0	$0	$0	$0	**$0**	0
Subtotal	$0	$0	$0	$0	$0	$0	**$0**	0
Oct	$0	$0	$0	$0	$0	$0	**$0**	0
Nov	$0	$0	$0	$0	$0	$0	**$0**	0
Dec	$0	$0	$0	$0	$0	$0	**$0**	0
Subtotal	$0	$0	$0	$0	$0	$0	**$0**	0
Jan	$0	$0	$0	$0	$0	$0	**$0**	0
Feb	$0	$0	$0	$0	$0	$0	**$0**	0
Mar	$0	$0	$0	$0	$0	$0	**$0**	0
Subtotal	$0	$0	$0	$0	$0	$0	**$0**	0
Apr	$0	$0	$0	$0	$0	$0	**$0**	0
May	$409	$0	$1	$0	$1	$0	**$411**	22,665
Jun	$409	$0	$1	$0	$1	$0	**$411**	22,836
Subtotal	$818	$0	$2	$0	$2	$0	**$822**	45,501
Total FY	$818	$0	$2	$0	$2	$0	**$822**	45,501

ANNUAL BUDGET
July 1, 2023 through June 30, 2024
Eland Solar 1 + Storage Project
($000)

	Revenues			Revenue Fund Disbursements		
Month	Monthly Power Costs	Interest Earnings (4)	Total Revenues	Operating Fund	Reserve Account	Total Revenue Fund Dis-bursements
Jul	$0	$0	$0	$0	$0	$0
Aug	$0	$0	$0	$0	$0	$0
Sep	$0	$0	$0	$0	$0	$0
Subtotal	$0	$0	$0	$0	$0	$0
Oct	$0	$0	$0	$0	$0	$0
Nov	$0	$0	$0	$0	$0	$0
Dec	$0	$0	$0	$0	$0	$0
Subtotal	$0	$0	$0	$0	$0	$0
Jan	$0	$0	$0	$0	$0	$0
Feb	$0	$0	$0	$0	$0	$0
Mar	$0	$0	$0	$0	$0	$0
Subtotal	$0	$0	$0	$0	$0	$0
Apr	$0	$0	$0	$0	$0	$0
May	$411	$0	$411	$411	$0	$411
Jun	$411	$0	$411	$411	$0	$411
Subtotal	$822	$0	$822	$822	$0	$822
0	$822	$0	$822	$822	$0	$822