SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

NOTICE OF REGULAR MEETING
Board of Directors

NOTICE IS HEREBY GIVEN by the undersigned, as the 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, December 19, 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 of the Meeting 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. **EXECUTIVE DIRECTOR REPORT**

The Executive Director will provide a report on the activities of the Authority since the last Board Meeting.

A. Working Group Update

3. **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

- Regular Meeting Minutes: November 21, 2024

B. Receive and File:

1. Finance Committee Meeting Minutes: November 4, 2024
2. Monthly Investment Report: October 2024
3. SCPPA A&G Budget Comparison Report: October 2024
4. Palo Verde Nuclear Generating Station Status Report: October 2024
5. Magnolia Power Project Operations Report: November 2024
6. Federal Legislative Report: November 2024

C. Resolution 2024-108

Approve Amendment No. 3 to The Long Term Service Agreement Between Southern California Public Power Authority and GE Vernova International LLC

4. **CHIEF FINANCIAL & ADMINISTRATIVE OFFICER REPORT**

A. Resolution 2024-109

Authorizing issuance of Revenue Bonds, 2025 Subordinate Refunding Series A approving certain documents and actions in connection therewith (Southern Transmission System Project)

B. Resolution 2024-110

Initial Authorizing Resolution: Preparation of all documents necessary for Southern Transmission System Renewal Project Revenue Bonds (Third Tranche)

5. **ASSET MANAGEMENT REPORT**

A. Resolution 2024-111

Approval of Revision No. 1 to Eland Solar & Storage Center, Phase I Project Budget

B. Resolution 2024-112

Approval of Revision No. 1 to Eland Solar & Storage Center, Phase 2 Project Budget

6. **PROGRAM DEVELOPMENT REPORT**

A. Reliability, Restoration, and Response (SR3) Benchmarking Summary Presentation by Pandora Consulting Associates, LLC

7. **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, Including Cap and Trade and Renewables Portfolio Standard Advisory

B. State Legislative Update, Including the Assembly Speaker's Affordability Agenda
C. Federal Issues Update
D. Recap of SCPPA's 2024 Government Affairs Strategic Planning Meeting

8. 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.

9. ADJOURNMENT

Signed by:
DAE0F3A6ECDE496...

Daniel E Garcia
Executive Director
Southern California Public Power Authority

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

MEMO

TO: SCPPA Board of Directors

FROM: Daniel E Garcia, Executive Director

DATE: Tuesday, December 10, 2024

RE: Working Group Updates

WORKING GROUP SUMMARY

ASSET MANAGEMENT

The Asset Management Working Group last met on October 24, 2024. The next meeting is scheduled for Thursday, January 23, 2024.

ASSISTANT GENERAL MANAGER (AGM)

The AGM Working Group last met on October 23, 2024. The next meeting is scheduled for Wednesday, January 22, 2024.

CYBERSECURITY

The Cybersecurity Working Group (CWG) did not meet this month as they currently meet on an ad-hoc basis. SCPPA has reached out to the CWG for updated contacts and representatives from the interested SCPPA Members. A couple of documents have been shared to the CWG regarding the guidelines for the group and the designation of representation for each Participating Member. We encouraged the CWG to review each of the documents, to assign a primary and secondary point of contact, and to make sure their

General Manager executes the Non-Disclosure Agreement before any meetings can be scheduled.

FINANCIAL INCENTIVES and RATES

The Financial Incentives and Rates Working Group was canceled this month as most Members attended the annual California Municipal Rates Group (CMRG). The conference was well attended, and the Members considered the content informative.

On November 17, 2024, SCPPA's Regulatory Affairs and Program Development teams invited all Program Development Working Groups (4) to attend a meeting to discuss current State regulatory issues impacting the Member's area within their respective utilities, and to share discuss the impact of recent state regulatory decisions. The meeting was well attended, and the Members asked many questions. Other SCPPA working groups were invited to attend as well.

The next Meeting is scheduled for December 17, 2024.

KEY ACCOUNTS

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

LEGAL

The next meeting of the Legal Working Group will take place on December 12, 2024. The topic for the December 12th meeting is energy prepay transactions.

LEGISLATIVE

The Legislative Working Group (LWG) met on November 30th. The LWG received a recap of the 2024 election, with The Ferguson Group and Samson Advisors providing a federal and state overview, respectively. The LWG also discussed Governor Newsom's recent executive order on electricity affordability; the governor's call for a special session to fund anticipated litigation against the federal government; an Assembly informational hearing on green energy permitting; and the current status of the West-wide Governance Pathways Initiative.

The next LWG meeting will be held on December 18th. The LWG and the Regulatory Working Group will also hold its annual SCPPA Government Affairs Strategic Planning meeting on December 6, 2024.

MUTUAL ASSISTANCE

The Mutual Assistance Sub-working Group (MASG) met on December 3rd. The MASG discussed the ongoing issues of supply chain and purchasing crucial equipment. With the upcoming change in the U.S. Administration, the MASG expects changes in tariffs that may exacerbate the issues even further. The MASG will decide on a new Chair and Vice Chair at the next MASG meeting.

The next MASG meeting is scheduled for January 7, 2025.

NATURAL GAS

The Natural Gas Working Group last met on October 22, 2024. The next meeting is scheduled for Tuesday, January 28, 2025.

PREPAY

The next meeting for the Prepay Working Group is on December 9th. The Group will receive an update on the further detailed review of the PPAs to confirm the suitability of the PPAs for a prepay transaction.

CUSTOMER PROGRAMS

The Customer Programs Working met on November 17th, as SCPPA's Regulatory Affairs and Program Development teams invited all SCPPA Working Groups (4) to attend a meeting to discuss current State regulatory issues impacting the Members' utility service areas. Members were asked to share their thoughts and experiences recent or proposed regarding the impact that past, current, and/or proposed legislation may have on their utilities and/or its customers. The meeting was well attended, and the Members asked many questions which created meaningful dialogue.

The next Meeting is scheduled for January 8, 2025.

REGULATORY

The Regulatory Working Group (RWG) met on November 20th and December 5th. The RWG discussed the following issues: Cap-and-Trade and Advanced Clean Fleets at the California Air Resources Board (CARB); SB 100 Report workshops and engagement at the California Energy Commission (CEC); the West Wide Governance Pathways Initiative; and CMUA's strategic planning for 2025. In addition, the RWG discussed SCPPA's 2025 Regulatory Working Group leadership and "Government Affairs Guiding Principles."

The next RWG meeting will be held on December 18th. The RWG and the Legislative Working Group held its annual SCPPA Government Affairs Strategic Planning meeting on December 6, 2024.

RENEWABLES

The Renewables Working Group (ReWG) did not meet in November. The ReWG will next meet on December 12th to discuss the ongoing developing projects and any new updates. We will also review any new proposals received in October and November. A Chair and Vice-Chair for the 2025 term will be selected as well.

RESOURCE PLANNING

The Resource Planning Working Group (RPWG) met on December 5th. The RPWG discussed the Standalone Energy Storage RFP proposals received so far since the last meeting. SCPPA expects to release a new Standalone Energy Storage RFP for 2025, as this year's RFP will expire at the end of December. In addition, the RPWG also discussed their interest in releasing a Distributed Energy Resource (DER) RFP for next year. A majority of the Members were willing to participate in the DER RFP as well.

The next RPWG meeting is scheduled for January 9, 2025, due to the January 1st holiday.

RISK MANAGEMENT

The Risk Management Working Group (RMWG) met on December 4th. The RMWG received an update on the development of SCPPA's Pro Forma Power Purchase Agreement and discussed the means for Member agency risk managers to review and provide any additional input. IID provided a presentation regarding updates to their Risk Management Policy. The RMWG also heard an update on SCPPA's RFP for an anti-market manipulation training provider.

The RMWG will next meet on February 5, 2025.

SAFETY

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

TRANSPORTATION ELECTRIFICATION

The Transportation Electrification Working Group meeting was cancelled due to the Thanksgiving holiday. However, The Group joined other SCPPA working groups on November 17th, as SCPPA's Regulatory Affairs and other SCPPA Working Groups met to discuss current State regulatory issues that were positively or negatively impacting Member's in their respective service territories. The meeting was well attended, and the Members were very engaged and requested that SCPPA hosts more of these types of joint meetings.

TRANSMISSION & DISTRIBUTION ENGINEERING & OPERATIONS (TD E&O)

The Transmission Distribution Engineering & Operation (TDE&O) Working Group (TDE&O WG) met on December 3rd. The TDE&O WG discussed the T&D Virtual Conference held on November 6th and suggested ideas for improving next year's conference. There was a suggestion for having it at an outside venue. A recommendation is to have it in Pasadena as previous T&D conferences were held there in the past. Another suggestion is to have Mutual Assistance, and the Safety Working Group provide presentations to provide a more diverse conference for all staff that participate in the T&D space.

The next TDE&O WG meeting is scheduled for January 7, 2025.

DEMAND RESPONSE & REDUCTION SUB-WORKING GROUP (DRRWG)

This Working Group meets on an Ad Hoc basis. No meeting is currently scheduled.

HYDROGEN & OTHER EMERGING TECHNOLOGIES

The Hydrogen and Other Emerging Technologies Working Group (H2ETWG) met on November 19th and December 5th. The initial focus of the group has been to identify policy principles related to state clean energy policy. The date of the next H2ETWG meeting is to be determined.

RECURRING/ROLLING SOLICITATIONS:

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).

NAME: Request for Proposals: 2024 Q3/Q4 SCPPA Renewables Energy Resources and Energy Storage Solutions

WORKING GROUP: Renewables

ISSUE DATE: July 23, 2024 **CLOSE DATE:** December 30, 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.

UPCOMING/RECENT SOLICITATIONS (NEW/CONTINUED SERVICES):

NAME: Request for Proposals (RFP): Anti-Market Manipulation Rules Training Services

WORKING GROUP: Risk Management

ISSUE DATE: August 13, 2024 **CLOSE DATE:** September 10, 2024

DESCRIPTION:

SCPPA Members are seeking a comprehensive compliance training program on Anti-Market Manipulation Rules tailored to energy market participants.

NAME: Request for Proposals (RFP): Mead-Adelanto Project (MAP) High-Voltage Direct Current (HVDC) Upgrade - Feasibility Study

DEPARTMENT: Asset Management

ISSUE DATE: August 2, 2024 **CLOSE DATE:** September 4, 2024

DESCRIPTION:

SCPPA issued an RFP to soliciting competitive proposals from qualified respondents for a Technical Consultant to conduct a feasibility analysis for a potential Mead-Adelanto Project (MAP) High-Voltage Direct Current (HVDC) Upgrade.

NAME: Request for Proposals (RFP): Energy Efficiency Direct Install and Audit Services

DEPARTMENT: Programs Development

ISSUE DATE: December 4, 2024 **CLOSE DATE:** December 31, 2024

DESCRIPTION:

SCPPA issued an RFP to solicit competitive proposals from qualified respondents to provide Energy Efficiency Audits and the Direct Install of Energy Efficient products.

Signed by:

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Daniel E Garcia, Executive Director
Southern California Public Power Authority

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 ***November 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 Board Vice President, Todd Dusenberry. Daniel Garcia, Executive Director, went through the emergency safety protocols for the in-person meeting participants. Mr. Dusenberry went through the web conference protocol. Ms. Salpi Ortiz took attendance.

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

Anaheim: Dukku Lee (B)
Azusa:
Banning: Jim Steffens (B)
Burbank: Mandip Samra (B)
Cerritos: Sergio Huizar (A)
Colton: Charles Berry (B)
Glendale: Scott Mellon (A)
IID:
LADWP: Ashkan Nassiri (A)
Pasadena: Kelly Nguyen (A)
Riverside: Scott Lesch (A)
Vernon: Todd Dusenberry (B)

1. NOTICE/AGENDA AND OPPORTUNITY FOR THE PUBLIC TO ADDRESS THE BOARD

Mr. Dusenberry noted that the meeting was noticed and posted as required under the Brown Act. Mr. Dusenberry invited comments from the public. There were no public comments.

2. EXECUTIVE DIRECTOR REPORT

A. Working Group Update

Mr. Garcia provided an update on the T&D E&O Conference, noting strong attendance and positive feedback from members. He congratulated the Los Angeles Department of Water and Power and Glendale Water & Power on the commercial operation of Eland Solar Phase I as of November 18, 2024. Mr. Scott Mellon expressed appreciation to SCPPA for their efforts on this project. Additionally, Mr. Garcia highlighted the success of SCPPA's inaugural Emerging Technologies Working Group meeting, which saw robust member participation and meaningful discussions related to hydrogen technology.

3. CONSENT CALENDAR

A. Minutes of the Board of Directors Meeting

- Regular Meeting Minutes: October 17, 2024

B. Receive and File:

1. FY 23-24 Q4 Budget-to-Actual Variance Report – Final
2. FY 23-24 Over/Under Billing Summaries – Final
3. Finance Committee Meeting Minutes: October 7, 2024
4. Monthly Investment Report: September 2024
5. Quarterly Investment Report: September 2024
6. SCPPA A&G Budget Comparison Report: September 2024
7. SCPPA Fiscal Year 2023-24 Audited Financial Statements
8. Moss Adams Report on Communications with Those Charged with Governance and Communication of Internal Control Related Matters for the fiscal year ended June 30, 2024
9. New SCPPA Underwriter Pool Memo and List
10. Palo Verde Nuclear Generating Station Status Report September 2024
11. Magnolia Power Project Operations Report: October 2024
12. Federal Legislative Report: October 2024

C. Resolution 2024-103
Approve the Funding Agreement between CMUA, and SCPPA for an Energy Efficiency Technical Reference Manual

D. Resolution 2024-104
Approve Amendment No.4 to the Master Goods and Services Agreement with Alternative Energy Systems Consulting, Inc. to extend the Agreement term until March 20, 2025.

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***			

4. CHIEF FINANCIAL & ADMINISTRATIVE OFFICER REPORT

A. Update on new Underwriter Pool

Ms. Aileen Ma, Chief Financial Officer, provided an update on the SCPPA's new Senior and Co-Manager Underwriter Pool and presented the list of Senior and Co-Managers approved by the Finance Committee.

5. ASSET MANAGEMENT REPORT

A. Resolution 2024-105

Approval of Revision No. 1 to FY 24/25 Ameresco Chiquita Landfill Gas Project Budget

Mr. Guss presented Resolution 2024-105 to the Board for consideration and approval.

Moved by: Kelly Nguyen, *Pasadena Water & Power*
Seconded: Mandip Samra*, Burbank Water & Power*

Ms. Ortiz took a Roll Call vote (Project 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***			

6. GOVERNMENT AFFAIRS REPORT

A. **Federal Issues Update, Including an Election Recap**
   Mr. Chris Kearney of The Ferguson Group reported on the 2024 federal election results and how it will potentially affect the energy sector in 2025.
B. **State Legislative Update, Including an Election Recap**
   Mr. Anthony Samson of Samson Advisors Company reported on the 2024 California election results and potential implications for SCPPA and the energy sector.
C. **State Regulatory Update, including Governor Newsom's Executive Order on Ratepayer Affordability**
   Mr. Mario De Bernardo, Government Affairs Director, presented a State Regulatory update including Governor Newsom's Executive Order on Ratepayer Affordability. Ms. Natalie Seitzman, Energy Policy Advocate, presented on the Westwide Governance Pathways Initiative.
D. **2025 Advocacy Events, including the Public Power Capitol Day and APPA Legislative Rally/SCPPA Fly-in**
   Mr. De Bernardo presented on upcoming 2025 advocacy events.
E. **Resolution 2024-106**
   Approve Amendment No. 1 to Professional Services Agreement with The Ferguson Group for federal government affairs consultant services to extend the term for three years, continue annual fee adjustments for the extended term, and increase the not-to-exceed amount

   Mr. De Bernardo presented Resolution 2024-106 to the Board for consideration and approval.

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***			

F. Resolution 2024-107

Approve Amendment No. 1 to Professional Services Agreement with Samson Advisors Company for state legislative consulting services to extend the term for three years and increase the not-to-exceed amount

Mr. De Bernardo presented Resolution 2024-107 to the Board for consideration and approval.

Moved by: Scott Mellon, *Glendale Water & Power*
Seconded: Mandip Samra, *Burbank 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***			

7. 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 discussed the idea of potentially forming a SCPPA sub-working group to address utility readiness and mutual assistance for the increased tourism associated with the Olympics and potentially to report to the Board on a quarterly basis. Ms. Samra shared updates on Burbank's preparations, including the construction of new hotels.

8. CLOSED SESSION

A. **Conference with Legal Counsel – Potential Initiation of Litigation; Govt. Code Section 54956.9(d)(4): One Case.**
The Board Entered into closed session at 11:37 a.m.

9. REPORT OUT OF CLOSED SESSION

The Board reconvened in Open Session at 11:44 a.m. Mr. Armando Arballo, Assistant General Counsel, reported that the Board had voted in Closed Session to approve Letter Agreements between SCPPA and each of Starpeak Geothermal, LLC and Whitegrass No. 1, LLC, respectively resolving certain matters under the Power Purchase Agreements between SCPPA and each of Starpeak Geothermal, LLC and Whitegrass No. 1, LLC, and that upon full execution thereof, the Letter Agreements will be available for public inspection. Mr. Arballo reported that the vote was unanimous by the Board Members present at the meeting.

10. ADJOURNMENT

Mr. Dusenberry adjourned the meeting at 11:46 a.m.

Respectfully Submitted,

____
Daniel E Garcia
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 **November 4, 2024**, at the SCPPA Glendora office and by teleconference from Imperial Irrigation District. The meeting commenced at 9:30 A.M. and adjourned at 11:12 A.M.

The meeting commenced with the Annual Disclosure Training followed by the Finance Committee Business Meeting.

Mr. Corbi (Committee Chair) took attendance prior to the Annual Disclosure Training. **Committee members/Alternate Committee members present for the Annual Disclosure Training were:** Brian Beelner *(Anaheim)*; Daniel Smith *(Azusa)*; Joseph Lillio *(Burbank)*; Ren Zhang *(Colton)*; Adrine Isayan *(Glendale)*; Belen Valenzuela (*IID-Teleconference*); Herman Leung *(Pasadena);* Brian Seinturier *(Riverside)*; and Richard Corbi *(Vernon).*

1. **<u>Annual Disclosure Training</u>**

   Mr. Hsu and Mr. Haytayan (Norton Rose Fulbright) provided the Annual Disclosure Training.

   The training concluded at 10:25 AM. The Finance Committee took a recess and reconvened at 10:35 AM.

Mr. Corbi (Committee Chair) took attendance following the recess, and prior to the start of the Financial Committee Business Meeting. **Committee members/Alternate Committee members present for the Finance Committee Business Meeting were:** Brian Beelner *(Anaheim)*; Daniel Smith *(Azusa)*; Jim Steffens (*Banning*); Joseph Lillio *(Burbank)*; Ren Zhang *(Colton)*; Adrine Isayan *(Glendale)*; Belen Valenzuela (*IID-Teleconference*); Peter Huynh (*LADWP*); Herman Leung *(Pasadena);* Brian Seinturier *(Riverside)*; and Richard Corbi *(Vernon).*

Others attendees were: Vivia Arellano (*IID-Teleconference*); Meline Carranza (*Riverside-Teleconference*); Victor Hsu *(Norton Rose Fulbright*); Mike Berwanger, Louise Houghton, and Jim Carbone (*PFM Financial Advisors-Teleconference*); Grace Mao *(LADWP/SCPPA-LA);* Francisco Olivares-Ortiz and Houbert Yousef (*LADWP/SCPPA-LA-Teleconference);* Daniel Garcia, Aileen Ma, Charles Guss, Christine Godinez, and Guadalupe Robles *(SCPPA);* Timmy Phuong, Donald Kaplan and Adrian Valdez (*SCPPA-Teleconference*)

The following were the business matters transacted by the Committee:

2. Opportunity for the Public to Address the Committee

Mr. Corbi invited any members of the public to provide comments. No public comments were made.

3. Consent Calendar

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

A. Minutes of the October 7, 2024 Finance Committee meeting
B. SCPPA Fiscal Year 2023-24 Audited Financial Statements
C. Final reports for Project Budget to Actual Comparison and Over/Underbillings for Fiscal Year 2023-24

Moved By: Richard Corbi
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			

4. Investment Reports

Ms. Mao presented the Monthly and Quarterly Investment Reports for the period ended September 30, 2024 to the Committee for review and consideration. The Committee recommended forwarding the reports to the Board for receipt and filing.

Moved By: Brian Beelner
Seconded By: Richard Corbi

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. <u>Administrative & General Expense (A&G) Budget Comparison Report</u>

Ms. Ma presented the A&G Budget Comparison Report for the quarter ended September 30, 2024 to the Committee for review and consideration. The Committee recommended forwarding the report to the Board for receipt and filing.

Moved By: Richard Corbi
Seconded By: Daniel Smith

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. **Ameresco Chiquita Landfill Gas Project Fiscal Year 2024-25 Budget Amendment**

Mr. Guss presented a revised project budget for the Ameresco Chiquita Landfill Gas Project for fiscal year 2024-25 to the Committee for review and consideration. The Committee recommended forwarding the revised project budget to the Board for approval. Project Vote with Burbank and Pasadena as project participants.

Moved By: Joseph Lillio
Seconded By: Herman Leung

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. **Underwriter Pool**

Ms. Ma provided an update on the Request for Qualifications issued to establish a new SCPPA Senior and Co-Manager Underwriter Pool and information on the evaluation process used in evaluating the proposals received. She also presented to the Committee for review and consideration a list of firms recommended by the evaluation team for the Senior and Co-Manager Underwriter Pool based upon the results of the evaluation. The Committee approved the recommended Senior and Co-Manager Underwriter Pool. The Board will be informed of the new pool.

Moved By: Richard Corbi
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			

8. <u>Southern Transmission Project Refunding Revenue Bonds</u>

Ms. Houghton (PFM Financial Advisors) provided the Committee with an update on the refinancing of the Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission Project).

9. <u>Market and Variable Rate Demand Obligation (VRDO) Update</u>

Ms. Houghton provided the Committee with a market update and VRDO status report.

10. <u>Unsolicited Proposals</u>

Ms. Houghton provided the Committee with a summary of an unsolicited proposal received from an investment banker.

11. <u>Prepay Working Group Update</u>

Ms. Ma provided the Committee with an update on the Prepay Working Group meetings.

12. <u>Committee Member and Staff Comments</u>

The Committee members and staff were given the opportunity to bring up informational items and/or suggest topics for future Committee meetings. No topics were suggested.

THE NEXT FINANCE COMMITTEE MEETING
WILL BE DECEMBER 2, 2024.

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

November 19, 2024

Mr. Daniel E. Garcia
Executive Director
Southern California Public Power Authority
1160 Nicole Court
Glendora, California 91740

Dear Mr. Garcia:

Enclosed is the ***October 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, Clean Energy, Milford Wind I, Milford Wind II, Windy Point/Flats, Ameresco, Apex Power, Copper Mountain Solar 3, Columbia 2 Solar, Eland 1, Eland 2, 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 October, the Investment Group coordinated variable debt service payments of $647,421 for the Magnolia Power, Linden Wind and Canyon Power Projects. Net swap payments of $514,609 were received 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 $2,674,419.

$261.3 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 $1.51 billion as of October 31, 2024, with an average yield of 4.65%. Total interest earned on the project funds for the month was $5.9 million and year to date was $23.1 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

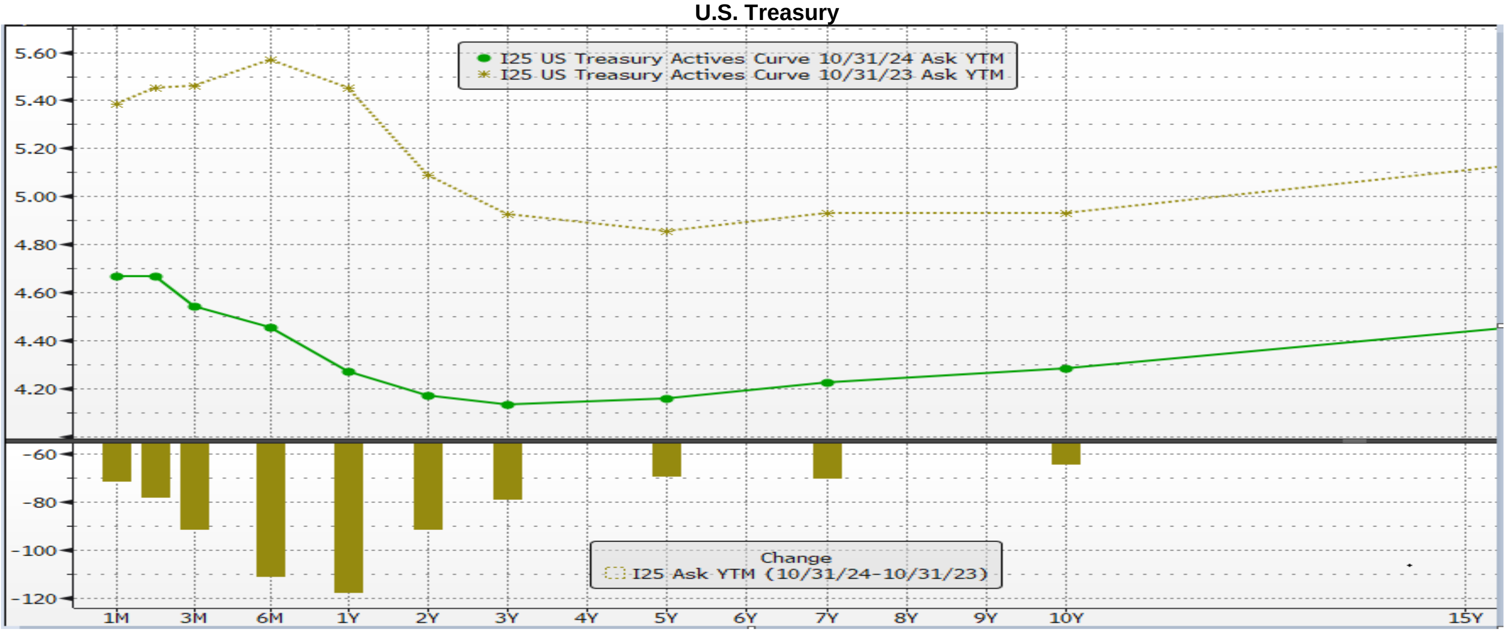
GRACE MAO
Manager of Finance
Los Angeles Department of Water & Power

Monthly Investment Report
October 31, 2024

Projects	Portfolio Yield	Investment Cost	Carrying Value	Market Value	Portfolio Life[2]	Cost of Capital[3]
Palo Verde	4.90%	37,137,483	37,217,833	37,210,793	0.23	N/A
San Juan	4.66%	3,182,551	3,184,654	3,183,051	0.13	N/A
Magnolia	4.91%	72,403,363	72,757,711	72,760,364	0.25	2.97%
STS	4.84%	16,714,414	16,807,930	16,805,918	0.21	4.70%
STS Renewal	4.91%	697,139,126	702,095,458	702,172,974	0.71	4.01%
Mead-Phoenix	4.68%	3,109,815	3,112,614	3,112,505	0.11	2.53%
Mead-Adelanto	4.68%	3,387,488	3,390,842	3,390,725	0.11	2.53%
Natural Gas	4.89%	49,980,911	50,009,134	50,034,875	0.40	6.06%
Natural Gas Prepaid[1]	4.96%	33,860,604	33,867,249	33,867,138	9.23	5.09%
Canyon Power	4.83%	12,487,764	12,543,057	12,544,366	0.16	2.74%
Apex Power	4.85%	42,362,932	42,573,818	42,562,512	0.18	4.32%
SCPPA Decomm Trust Fund	3.60%	195,738,961	195,924,173	193,263,366	1.22	N/A
Project Stabilization Fund	4.82%	137,396,198	137,789,635	137,762,039	0.91	N/A
Tieton	4.97%	4,631,051	4,663,386	4,665,170	0.10	2.67%
Clean Energy	4.91%	14,619,033	14,619,033	14,619,033	5.78	N/A
Linden Wind	4.87%	8,280,882	8,316,260	8,316,202	0.08	3.15%
Milford Wind 1	4.81%	17,379,819	17,451,030	17,445,406	0.15	5.08%
Milford Wind 2	4.80%	7,365,871	7,413,502	7,414,164	0.23	1.05%
Windy Point Flats	4.73%	18,257,187	18,355,910	18,357,717	0.27	3.55%
Pwr Purchase Agreements Combined	3.91%	113,996,513	114,348,584	114,347,751	0.05	N/A
San Juan Reclaim Trust Fund	4.29%	18,015,924	18,053,671	17,985,679	0.24	N/A
San Juan Decomm Trust Fund	4.76%	3,239,155	3,255,067	3,255,135	0.33	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.*

U.S. Treasury



Tenor	I25 Ask YTM US Treasury Actives Curve 10/31/24	I25 Ask YTM US Treasury Actives Curve 10/31/23	I25 Ask YTM (Change) 10/31/24-10/31/23
1M	4.666	5.384	-71.80
2M	4.667	5.450	-78.30
3M	4.542	5.462	-92.00
6M	4.456	5.569	-111.30
1Y	4.269	5.450	-118.10
2Y	4.170	5.087	-91.70
3Y	4.133	4.926	-79.30
5Y	4.158	4.854	-69.50

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

MEMO

To: SCPPA Finance Committee

From: Aileen Ma, Chief Financial & Administrative Officer

Date: December 2, 2024

Re: **FY 2024-25 Administrative & General (A&G) Expense Budget to Actual Comparison Report – October 2024**

As of October 31, 2024, total A&G expenditures were $3,367,332 which was $355,188 or 9.5% under the year-to-date budget.

Total Indirect A&G expenditures were $1,855,300 which was $185,426 or 9.1% under budget. The under budget was primarily due to the timing of expenditures and invoices from vendors and consultants. The under budget was partially offset by slightly higher than anticipated utility bills for the SCPPA Glendora buildings.

Total Direct A&G expenditures were $1,512,032 which was $169,762 or 10.1% under budget. The under budget was primarily due to the timing of expenditures for legal services and trustee fees and savings in agent billable costs due to personnel vacancy. The under budget was partially offset by other professional services for audit expenses relating to the Magnolia Power Project and Tieton Hydropower Project Operating Agents.

Southern California Public Power Authority
FY 2024-25 Adminstrative & General (A&G) Expense Budget to Actual
October 31, 2024

	ANNUAL BUDGET FY 2024-2025	YTD BUDGET 10/31/2024	YTD ACTUAL 10/31/2024	Under / (Over) Budget	% Variance
Salaries	$ 3,039,700	$ 1,013,236	$ 992,593	$ 20,643	2.0%
Employee Benefits	838,300	393,100	343,633	49,467	12.6%
Office Building Costs	154,590	51,542	52,816	(1,274)	-2.5%
Office Equipment and IT	110,290	56,874	54,075	2,799	4.9%
Office Expenses	61,400	20,464	17,225	3,239	15.8%
Insurance	164,000	88,466	87,037	1,429	1.6%
Meeting Expense	37,500	12,500	7,680	4,820	38.6%
Travel and Conferences	52,000	17,328	2,077	15,251	88.0%
Staff Training/Development	26,000	8,664	2,208	6,456	74.5%
Memberships and Dues	26,010	1,802	1,237	565	31.3%
Subscriptions	20,760	5,708	4,946	762	13.4%
Gov't Affairs (Sacramento Office)	184,530	58,134	41,681	16,453	28.3%
Legislative Advocacy	368,000	154,336	151,551	2,785	1.8%
Regulatory Advocacy	220,000	73,336	70,019	3,317	4.5%
General Legal Services	140,000	46,672	14,079	32,593	69.8%
Auditing Services	4,930	3,500	3,339	161	4.6%
Consulting & Other Services	69,500	23,164	4,366	18,798	81.2%
Financial Advisor	90,000	30,000	22,500	7,500	25.0%
Budget Contingency	140,190	-	-	-	0.0%
Subtotal	**$ 5,747,700**	**$ 2,058,826**	**$ 1,873,062**	**$ 185,764**	**9.0%**
Glendora Project Accounting - Direct A&G	(54,300)	(18,100)	(17,762)	(338)	1.9%
TOTAL INDIRECT A&G	**$ 5,693,400**	**$ 2,040,726**	**$ 1,855,300**	**$ 185,426**	**9.1%**
Outside Counsels	$ 456,000	$ 152,000	$ 66,833	$ 85,167	56.0%
Auditing Services	365,260	255,000	250,661	4,339	1.7%
Consulting & Other Services	35,500	11,836	15,112	(3,276)	-27.7%
Project Travel Costs	18,350	6,118	1,816	4,302	70.3%
WREGIS Fees	18,160	6,056	2,776	3,280	54.2%
Agent Billable Costs	3,074,300	1,024,767	974,313	50,453	4.9%
Trustee Fees	335,750	111,917	87,758	24,159	21.6%
Rating Agency Fees	150,500	96,000	95,000	1,000	1.0%
Subtotal	**$ 4,453,820**	**$ 1,663,693**	**$ 1,494,270**	**$ 169,424**	**10.2%**
Glendora Project Accounting	54,300	18,100	17,762	338	1.9%
TOTAL DIRECT A&G	**$ 4,508,120**	**$ 1,681,793**	**$ 1,512,032**	**$ 169,762**	**10.1%**
TOTAL A&G EXPENSES	**$ 10,201,520**	**$ 3,722,519**	**$ 3,367,332**	**$ 355,188**	**9.5%**

SCPPA BOARD MEETING
PALO VERDE NUCLEAR GENERATING STATION
STATUS REPORT

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

- Unit 1 is operating at full power and is in its 370th day of continuous operation.
- Unit 2 is operating at full power and is in its 4th day of continuous operation.
- Unit 3 is operating at full power and is in its 187th day of continuous operation.

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

	Capacity Factor
Unit 1	99.4%
Unit 2	12.6%
Unit 3	98.5%
Station	70.2%

Budget:

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

(In $millions)

Year-to-Date	Budget	Actual	Variance
O&M	575.82	570.96	(4.86)
Capital	227.55	218.22	(9.33)
Fuel	209.53	191.03	(18.50)
Total	1,012.89	980.21	(32.69)

The year-end budget projection is as follows:

Year-End	Budget	Forecast	Variance
O&M	724.00	720.80	(3.19)
Capital	258.00	259.07	1.07
Fuel	210.06	202.42	7.64
Total	1,192.06	1,182.29	(9.76)

Developments:

- Due to a lack of control system commonality and control systems that are universally obsolete, the Strategic Modernization Project (SMP) is a method by which to solve this problem to improve system reliability and as an opportunity to improve commonality. SMP has been set to start in 2024 and will run until the end of Q3 2036, in 4 different Phases from procuring to planning and implementation.
- Since the significantly increasing number of trips caused by lack of chiller reliability (143 trips to 3 Units since 2019), the current chillers are to be replaced with newer and much larger ones. This project has already began and is projected to be completed by beginning of Q2 2028.
- Three different vendors will be used to carry out the project in regards to all the control oil upgrades: S&L, Hydra-Lube, GE. S&L's scope has a projected PO Revision 0 date of March 2025 with a $258,000 design impact with the addition of the accumulator. Hydra-Lube's scope has already begun, with equipment to be ordered still and a lead time of 24-30 weeks and an estimate of $500,000 per manifold per unit and an additional $90,000 for the accumulator upgrade per unit. GE is still in their analysis phase with an estimated completion date of it by November 2024.

Sean Kigerl
(818) 238-3774
December 19, 2024

MAGNOLIA POWER PLANT
OPERATIONS REPORT
November 2024

Reporting Period

November 1-30, 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 November and one (1) YTD.

Plant Performance Information

- **Availability:** 100.0% in November, 98.3% fiscal year-to-date (FYTD), and 96.8% YTD. (A table showing monthly plant availability for the past twenty-three months is attached.)
- **Unit Capacity Factor (240 MW):** 79.5% in November, 80.7% FYTD, and 75.2% YTD.
- **Fired Factored Hours:** 720.0 hours in November 2024.
- **Plant Starts (5 starts/month allowed):** Zero (0) starts used during November.
- **Plant Operating Hours (8,322 hours/year allowed):** 7,782.6 hours YTD.
- **Statistics:** Details are provided on the attached monthly production report entitled "Year-to-Date Summary of Statistics CY 2024 & FY2024-25".

Plant Outage Summary and Other Information

- There were no outages at MPP during the month of November 2024. A table entitled "Outage Summary" is attached which 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.
- Preparations are underway for the upcoming planned outage. MPP will be shut down on December 8, 2024, to perform an offline water wash of the combustion turbine compressor and balance of plant maintenance. MPP is scheduled to be restarted on December 17, 2024.
- There were no instances of stranded energy in November 2024 (a table showing stranded energy by month is attached).

MAGNOLIA MONTHLY PRODUCTION REPORT
Year-to-Date Summary of Statistics
CY 2024 & FY2024-25

		2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024		
		Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**FYTD**	**YTD**
ENERGY															
Combustion Turbine (Gross)	MWH	103,171	86,488	64,558	71,736	68,986	70,804	101,587	97,251	74,870	91,470	88,203		453,381	919,124
Steam Turbine	MWH	58,944	52,629	42,990	49,726	50,578	47,545	61,116	61,303	50,222	56,523	54,119		283,282	585,694
Plant Generation (Gross)	MWH	162,115	139,116	107,548	121,462	119,564	118,349	162,702	158,554	125,092	147,994	142,322		736,664	1,504,818
Plant Auxiliaries (Unit Aux.)	MWH	5,286	4,779	3,945	4,712	4,932	4,484	5,490	5,461	4,550	5,314	5,025		25,840	53,978
Plant Auxiliaries (Reserve)	MWH	7	6	583	6	6	339	7	6	335	6	6		360	1,307
Plant Generation (Net)	MWH	156,829	134,337	103,603	116,751	114,632	113,865	157,212	153,093	120,542	142,680	137,297		710,824	1,450,840
Capacity Factor (240 MW Net)	%	87.8%	80.4%	58.0%	67.6%	64.2%	65.9%	88.0%	85.7%	69.8%	79.9%	79.5%		80.7%	75.2%
THERMAL EFFICIENCY															
Combustion Turbine (Gross)	BTU/KWh	11,348	11,874	12,628	13,040	13,473	12,560	11,419	11,611	12,230	11,825	11,832		11,756	12,074
Total Plant (Gross)	BTU/KWh	7,228	7,384	7,588	7,702	7,774	7,527	7,214	7,274	7,471	7,312	7,333		7,313	7,415
Total Plant (Net)	BTU/KWh	7,472	7,646	7,877	8,013	8,108	7,823	7,466	7,533	7,753	7,585	7,602		7,579	7,691
AVAILABILITY															
Hours in the Month	Hours	744.0	696.0	744.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	720.0		3,672.0	8040.0
Plant Operating Hours	Hours	744.0	696.0	610.5	720.0	744.0	659.6	744.0	744.0	656.5	744.0	720.0		3,608.5	7782.6
Duct Burner Operating Hours	Hours	8.6	4.0	2.8	0.7	0.1	12.3	110.8	203.7	106.3	7.4	0.2		428.5	456.8
Plant Availability	%	100.0%	100.0%	82.1%	100.0%	100.0%	91.6%	100.0%	100.0%	91.2%	100.0%	100.0%		98.3%	96.8%
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		0.0	0.0
Planned Outage Hours	Hours	0.0	0.0	132.5	0.0	0.0	60.4	0.0	0.0	60.0	0.0	0.0		60.0	252.9
Forced Outage Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	0.0	0.0		3.5	3.5
Forced Outage	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%		0.1%	0.0%
Total Hours Offline	Hours	0.0	0.0	132.5	0.0	0.0	60.4	0.0	0.0	63.5	0.0	0.0		63.5	256.4
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		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		0.0	0.0
Total Factored Fired Hours	Hours	744.0	696.0	610.5	720.0	744.0	659.6	744.0	744.0	656.5	744.0	720.0		3,608.5	7,782.6
(FFH) Before Next Inspection	Hours	8,389	7,693	7,083	6,363	5,619	4,959	4,215	3,471	2,815	2,071	1,351		-	-
Estimated Date of Next Major Outage														Feb 2025	
FUEL USAGE AND QUALITY															
Combustion Turbine	DTH	1,170,829	1,026,952	815,267	935,442	929,469	889,288	1,159,967	1,129,164	915,688	1,081,607	1,043,654		5,330,080	11,097,328
Duct Burner	DTH	1,012	227	793	49	6	1,474	13,812	24,152	18,933	595	14		57,507	61,067
Duct Burner	MMSCF	1.0	0.2	0.8	0.0	0.0	1.4	13.2	23.0	18.0	0.6	0.0		55	58
Duct Burner Fuel Remaining	MMSCF	554.0	553.8	553.0	553.0	553.0	551.6	538.4	515.4	497.4	496.8	496.8		-	-
Total Plant Usage	DTH	1,171,841	1,027,179	816,060	935,491	929,475	890,762	1,173,779	1,153,316	934,622	1,082,202	1,043,668		5,387,587	11,158,395
Gas BTU (HHV)	BTU/SCF	1,039	1,039	1,033	1,030	1,030	1,032	1,027	1,031	1,026	1,031	1,050		1,033	1,033

Magnolia Power Plant - Outage Summary

Outages During the Reporting Period November 1-30, 2024				
Outage Type	**Start Date/Time**	**End Date/Time**	**Hours**	**Comments**
None				

Summary of Outages During the Past Twelve Months				
Outage Type	**Start Date**	**End Date**	**Hours**	**Cause**
PO	December 15, 2023	December 18, 2023	60.5	CT water wash
PO	March 15, 2024	March 21, 2024	132.5	Boiler Inspection/CT water wash
PO	June 21, 2024	June 24, 2024	60.4	CT water wash
PO	September 20, 2024	September 23, 2024	60.00	CT water wash
FO	September 23, 2024	September 23, 2024	3.48	CT fuel valve solenoid failure

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

Magnolia Power Plant - Availability Summary Table

Monthly	Quarterly	Semi-Annually	Annually
Jan-23 99.1%	Q1 '23 93.5%	H1 '23 95.4%	Yr '23 96.3%
Feb-23 100.0%			
Mar-23 82.1%			
Apr-23 100.0%	Q2 '23 97.2%		
May-23 100.0%			
Jun-23 91.6%			
Jul-23 100.0%	Q3 '23 97.3%	H2 '23 97.3%	
Aug-23 100.0%			
Sep-23 91.6%			
Oct-23 100.0%	Q4 '23 97.3%		
Nov-23 100.0%			
Dec-23 91.9%			
Jan-24 100.0%	Q1 '24 93.9%	H1 '24 95.6%	
Feb-24 100.0%			
Mar-24 82.1%			
Apr-24 100.0%	Q2 '24 97.2%		
May-24 100.0%			
Jun-24 91.6%			
Jul-24 100.0%	Q3 '24 97.1%		
Aug-24 100.0%			
Sep-24 91.2%			
Oct-24 100.0%			
Nov-24 100.0%			

Magnolia Power Project

2024-2028

Scheduled Inspection Plan with 32K Hardware

Offline Water Wash

Hot Gas Path / Minor Inspection

Major Inspection

As of **Dec. 3rd, 2024**

Total Fired Time | **142,947.0 Hours**

Total Fired Hours PROJECTED ANNUALLY	**2024** (8,322 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	70 139,117 Hrs. 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 **Upcoming Inspections** Minor Inspection CT Rotor Replacement **02/28/2025-04/21/2025**	71 141,241 Hrs. 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**
All Future Dates are estimates based on run hours and are subject to change	72 December 2024 **Offline 6:00 PM 12/08/2024** **Online 7:00 AM 12/17/2024**		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	143,428 Hours	150,808 Hours	159,256 Hours	167,704 Hours	176,176 Hours

Stranded Energy Monthly Report

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

Memo

TO: Southern California Public Power Authority
FROM: TFG
RE: Federal Legislative Report
DATE: December 12, 2024

November 2024 Federal Report

This legislative report covers activities related to appropriations, energy, and environment as well as telecommunication and cybersecurity issues from November 1 through November 30, 2024.

Executive Summary

Congressional Calendar. The House and Senate were in session for one week in November, primarily for new member orientation and to pass not controversial bills.

FY 25/25 Appropriations. The federal government is currently operating Continuing Resolution (CR) that continues funding of agencies and programs at this year's levels – regular fiscal year ended on September 30th – through December 20.

Energy and Environment. Republicans will control all branches of government for the next two years – albeit with very tight margins in the House. How the GOP control affects key issues important to public power in general and SCPPA in particular remains to be seen. Matters to watch include how the expiring 2017 tax bill provisions as well as the ongoing clean energy provisions of the Inflation Reduction Act are addressed.

Telecommunications and Cybersecurity. Among other activities, Verizon Communications and Frontier Communications entered into a definitive agreement for Verizon to acquire Frontier, which would bring Frontier's 7.2 million fiber locations and 2.2 million fiber subscribers in 25 states, including California, under Verizon's ownership.

FY 2024/25 Appropriations Process

Earlier this Fall, President Joe Biden signed the Continuing Appropriations and Extensions Act, 2025 (P.L. 118-83) into law, averting a government shutdown that would have begun on October 1 and funding the federal government at enacted Fiscal Year (FY) 2024 funding levels through Friday, December 20, 2024. The House and Senate passed the Continuing Resolution (CR) by votes of 341-82 and 78-18, respectively, on September 25. Enactment of the CR has provided congressional leaders an additional twelve weeks to finalize and pass all twelve FY 2025 spending bills.

The House Appropriations Committee has marked up and advanced all 12 of their versions of their Fiscal Year (FY) 2025 appropriations bills; in June and July, the full House passed five of these FY25 spending bills on the floor (Military Construction-Veterans Affairs; Defense; Homeland Security; State-Foreign Operations; and Interior-Environment).

The Senate Appropriations Committee has marked up and advanced 11 of the 12 FY25 spending bills (only the Homeland Security spending bill has yet to be considered); none of these 11 spending bills have received votes on the Senate floor thus far.

Congress returned from the campaign trail in November and began serious discussions on how best to fund the government for the remainder of the fiscal year. Failure to reach agreement by December 20, would likely lead to a government shut down—an outcome no serious lawmaker will support. Should Congress, fail to reach such agreement, it would lead to an extension of the CR into the new year, likely mid to late March 2025.

Energy and Environment

How Will Federal Election Results Affect Public Power?

Republicans will control the White House, Senate (53-47) and House of Representatives (220-215 – 218 for control) or the next two years.

While it is much too early to fully outline the agenda for the GOP-controlled Congress, at a minimum, the tax debate will take center stage. Both chambers will likely look to early moves in the budget process – using a legislative vehicle referred to as “reconciliation” to pass key priorities (measures passed under reconciliation only need a simple majority to pass – not the typical 60 votes that are usually required). High on the priority list will be addressing the 2017 tax bill as many of its provisions are expiring in 2025 as well as addressing border related matters and energy security provisions.

There has been much media speculation regarding repealing, or blocking, the continued implementation of clean energy tax credits established under the Inflation Reduction Act (IRA) to potentially offset part of the costs of the new tax bill. While some of that may occur as it relates to electric vehicles, Republicans will face real challenges trying to “claw back” remaining funds, as there are several factors at work regarding their preservation that complicate that effort. Perhaps most notably, there are GOP members in both chambers who have voiced concern over repealing the IRA’s clean energy incentives since they are supporting projects in their districts. Given the slim majority margins – especially in the House – GOP leaders cannot afford to lose a single vote on a tax bill. Therefore It is likely there will be much “horse trading” that may well, ultimately, yield retention of many of the IRA credits in some form (especially wind and solar) when a final bill goes to the president.

Biden’s Plans for Remainder of Term

President Biden plans to keep his team focused on their own priorities for his final days in office as they prepare for an “orderly” transition to the incoming Trump administration. As he said recently, “We have 74 days to finish the term, our term. Let's make every day count.” Specifically, the top priorities for the Biden administration’s remaining days in office include keeping the government funded, assisting hurricane victims, passing the National Defense Authorization Act and maximizing the number of judicial nominees confirmed. President Biden has spoken with President-elect Donald Trump to congratulate him on his win and Biden assured him that Biden Administration is committed to a peaceful transfer of power.

Action On Energy Project Permitting Legislation – Lame Duck?

Currently, legislation to update permitting rules in an effort to speed up the development of energy infrastructure and boost production of both clean energy and fossil fuels is pending in the Senate. However, the bill, written by Chair Joe Manchin (I-WV) and Ranking Republican John Barrasso (R-WY) has drawn divisions among Democrats on the committee who disagreed on whether the mix of provisions measures would adversely impact Biden Administration climate goals. Manchin and Barrasso have developed the bill after more than a year of negotiations.

The legislation would expedite approvals for not just coal, oil and gas development — priorities for Republicans and Manchin — but also renewable energy, critical mineral mining projects, and the transmission lines that Democrats favor to help spread the growth of wind and solar. Democrats who voted for the bill agreed with renewable industry groups who say the legislation provides enough new incentives for their businesses to be worthy the fossil fuel trade-off. They argued the transmission elements would build on recent and planned actions by FERC to allow clean energy that was assisted by expansion of credits provided in the Inflation Reduction Act not to be stranded because it can't connect to the grid.

While action before the full Senate – and House -- in the Lame Duck remain uncertain, passage remains a high priority for the bill’s sponsors which in turn generated intense and ongoing “Behind the scenes” discussions throughout November.

Telecommunications and Cybersecurity

Telecommunications

Spectrum Package: Senate Commerce, Science, and Transportation Committee Chair Maria Cantwell (D-WA) is hoping to get her Spectrum and National Security Act (S. 4207) into an end-of-the-year package. The bill would reserve $7 billion for the Affordable Connectivity Program, $3.08 billion for network “rip-and-replace” efforts, and $2 billion for next-generation 911 (NG-911). It also would extend the FCC’s spectrum auction authority to 2029.

Broadband Permitting Opposition: In response to several industry trade groups expressing support for the measure, the National League of Cities (NLC), the U.S. Conference of Mayors (USCM), the National Association of Counties (NACo), and the National Association of Telecommunications Officers and Advisors (NATOA) sent a letter to House Speaker Mike Johnson (R-LA) and House Minority Leader

Hakeem Jeffries (D-NY) to reiterate their “strong opposition” to the American Broadband Deployment Act (ABDA) (H.R. 3557), which combines a number of bills introduced by Republicans designed to “streamline” federal, state, and local permitting reviews. The legislation “represents an unprecedented and dangerous usurpation of local governments’ authority to manage public rights-of-way and land use,” NLC and other government groups said.

Interagency Broadband Coordination: The National Telecommunications and Information Administration (NTIA) released a report based on the Government Accountability Office’s recommendation to assess legislative barriers in coordinating Federal broadband programs, and how to address those barriers. In the report, NTIA recommended Congress or agencies work to align broadband programs through standardization “to reduce complexity and unnecessary variation for applicants and other stakeholders”; to coordinate the impact of broadband funding and to document standard operating procedures; and to improve and integrate broadband data and mapping.

Verizon-Frontier Merger: Verizon Communications and Frontier Communications entered into a definitive agreement for Verizon to acquire Frontier, which would bring Frontier’s 7.2 million fiber locations and 2.2 million fiber subscribers in 25 states, including California, into Verizon’s fold. Frontier said it is committed to building out another 2.8 million fiber locations by the end of 2026. Those 10 million fiber passings when combined with Verizon’s FiOS buildouts will give Verizon 25 million fiber locations in 31 states and the District of Columbia.

Cybersecurity

Cybersecurity Collaboration Bill: The Joint Cyber Defense Collaborative Act (H.R. 9768) has cleared the House Homeland Security Committee by a vote of 17-13. Introduced by Rep. Eric Swalwell (D-CA), the bill would create a JCDC Advisory Council, direct the Cybersecurity and Infrastructure Security Agency's (CISA) director to create a charter for the JCDC, and adopt new transparency mechanisms. The JCDC's mission is to complement the efforts of the intelligence community and law enforcement, and participants include service providers, infrastructure operators, cybersecurity companies, critical infrastructure sector companies, and subject matter experts.

Cyber Task Force Bill: Rep. Laurel Lee (R-FL) introduced the Strengthening Cyber Resilience Against State-Sponsored Threats Act (H.R. 9769), which would require the establishment of a federal interagency task force chaired by the director of the Cybersecurity and Infrastructure Security Agency or the director’s designee to break down “siloes” and promote collaboration by federal cyber defenders to address Chinese government hacking campaigns. The task force would specifically focus on cyber threats to the U.S. from Chinese government cyber campaigns, including Volt Typhoon, which federal officials have identified as an effort to pre-position malware in U.S. critical infrastructure in advance of a conflict between China and the U.S.

SCPPA
Southern California Public Power Authority

AGENDA ITEM STAFF REPORT

MEETING DATE: 12/19/2024 **RESOLUTION NUMBER:** 2024-108

SUBJECT: Amendment No. 3 to Long-Term Service Agreement Between Southern California Public Power Authority and GE Vernova International LLC for the Apex Power Project

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	☐		
Executive Director	☐		

MEMBER PARTICIPATION:

Sponsoring Member: LADWP

Other Members Potentially Participating:
None

Approved by Executive Director: Signed by: DAE0F3A6ECDE496...

RECOMMENDATION:

Adopt Resolution No. 2024-108 to authorize Amendment No. 3 to a Long-Term Service Agreement ("LTSA") between Southern California Public Power Authority ("SCPPA") and GE Vernova International LLC ("GE") for the Combustion Turbine Generators and Steam Turbine Generators at the Apex Power Project.

BACKGROUND:

In March of 2014, SCPPA purchased the Apex Generating Station ("Apex") and concurrently entered into a Power Sales Agreement with LADWP for 100% of the facility output. As part of this transaction, asset purchase service contracts were reassigned to SCPPA by the previous owner of the plant, Las Vegas Power Company LLC, and such reassigned contracts included the LTSA with GE for the Combustion Turbine Generators and Steam Turbine Generators. Assignment of the LTSA assured continued safe and environmentally friendly operation of Apex. The LTSA has been amended twice by SCPPA to provide much needed major equipment updates to Apex.

To be proactive about planned operations and maintenance services and the associated personnel at Apex, LADWP, as operating agent for the project, has negotiated an amendment to the LTSA with GE ("Amendment No. 3"). The LTSA is set to expire after each turbine has reached its gas turbine end date as defined in the LTSA. This Amendment No. 3 will extend the gas turbine end date for each turbine such that the gas turbine end dates shall expire on the earliest of the following for each turbine: date on which such gas turbine accrues one-hundred seventy thousand (170,000) hours of combustion turbine operation, or (ii) the date on which the gas turbine requires a "Hot Gas Path Inspection" or a "Major Inspection" (as such terms are defined in the LTSA) following the completion of the fifth Hot Gas Path Inspection on such gas turbine; or (iii) December 31, 2045. The amendment shall also, among other things, provide SCPPA with a right to terminate the LTSA for convenience subject to payment of a termination fee and enable SCPPA and LADWP the option to have LADWP self-provide installation services.

DISCUSSION:

The LTSA continues to be needed to provide for the planned replacement of Combustion Turbine, Steam Turbine and Generator Parts along with installation services for these parts and Monitoring and Diagnostic services. Due to the limited production numbers of these large generators, it is not commercially viable for SCPPA to consider third party parts suppliers and service providers as they lack the expertise to ensure environmentally compliant, safe, and reliable operation. By renewing the LTSA, SCPPA secures continued access to genuine Original Equipment Manufacturer ("OEM") parts, which are vital for ensuring optimal equipment performance, reliability, and adherence to safety standards. Additionally, the LTSA includes predictive maintenance, helping to minimize unexpected repairs and improve overall efficiency, resulting in lower operational costs. GE's OEM parts are specifically designed for their equipment, enhancing durability, reducing breakdowns, and improving overall equipment availability. Furthermore, the LTSA guarantees performance and emissions standards, availability targets, and coverage for both scheduled and unscheduled maintenance, ensuring continued operational excellence for the Apex Power Project.

- **Selection Method:** The Amendment to the LTSA is exempt from Sealed Competitive Bidding requirements under Section 2(b)(5) of SCPPA's Procurement Code, which applies where the SCPPA Purchasing Manager determines in accordance with the Procurement Code and the implementation procedures that only a Sole Source of supply is available for a good or service. The memorandum supporting the sole source determination is attached to this report as Attachment 1.

- **SCPPA's Authority:** In accordance with the Joint Powers Agreement, SCPPA may facilitate contracts for transactions involving procurement of electric energy and electric generation capacity for SCPPA Members.

- **California Environmental Quality Act (CEQA):** The Board's action is categorically exempt from CEQA as the proposed GE repairs to existing facilities fall under CEQA Guideline Section 15301 (minor alteration to an existing facility used to provide electric power, involving negligible or no expansion of use) and Section 15302 (replacement or reconstruction of existing utility systems and/or facilities involving negligible or no expansion of capacity).

FISCAL IMPACT: Costs are 100% reimbursable by LADWP through the Apex Power Project agreements.

ATTACHMENTS:

1. Memorandum dated December 03, 2024, supporting sole source determination
2. Resolution No. 2024-108

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

MEMO

To: Aileen Ma, SCPPA Purchasing Manager

From: Charles Guss, Senior Asset Manager

Date: December 3, 2024

Re: Sole Source Justification: GE Vernova International, LLC

Background

GE Vernova International, LLC ("GE") is the Original Equipment Manufacturer ("OEM") of the Apex gas turbine generators and has provided parts and maintenance services for the gas turbine generators at Apex under a Long-Term Service Agreement ("LTSA"). The LTSA dates back to 2001 when the facility was built. The LTSA was assigned to SCPPA with the purchase of the Apex facility in 2014. Without amendment, the LTSA will expire after 112,000 fire hours, which is projected to be in the second quarter of 2025. As agent for SCPPA, LADWP has determined that the LTSA continues to be needed to provide for the planned replacement of Combustion Turbine, Steam Turbine and Generator Parts along with installation services for these parts and Monitoring and Diagnostic services.

SCPPA Procurement Code

Under SCPPA's Procurement Code, the LTSA with GE is exempt from Sealed Competitive Bidding requirements under section 2(b)(5) of the Procurement Code as a sole source contract. Procurement Code section 2(b)(5) allows for sole sourced contracts where the Purchasing Manager determines "that only a Sole Source of supply is available for a good or service." Section 1 of the Procurement Code defines "Sole Source" as a "good or service awarded without a competitive process because it is the only good or service satisfying the Authority's specific need, as justified by at least one of the criteria in the Authority's implementation procedures and the supporting documentation requested therein." SCPPA's approved Solicitation and Contract Management Procedure provides that Sole Source procurements may be justified based upon at least one of several specified criteria, including the following criteria, which apply to this procurement:

"Competitive sourcing is precluded because of the existence of patents, copyrights, and special processes, control of raw materials by providers or similar circumstances."

Under the SCPPA Procurement Code, Sole Source contracts over $50,000 require approval of the Board of Directors. Based on this recommendation, Asset Management will also seek SCPPA Board of Directors' approval of the LTSA with GE in support of the Apex Generating Station.

Sole Source Justification

Due to the limited production numbers of these large generators, it is not commercially viable for SCPPA to consider third party parts suppliers and service providers as they lack the expertise to ensure environmentally compliant, safe, and reliable operation. By renewing the LTSA, SCPPA secures continued access to genuine Original Equipment Manufacturer ("OEM") parts, which are vital for ensuring optimal equipment performance, reliability, and adherence to safety standards. Additionally, the LTSA includes predictive maintenance, helping to minimize unexpected repairs and improving overall efficiency, resulting in lower operational costs. GE's OEM parts are specifically designed for their equipment, enhancing durability, reducing breakdowns, and improving overall equipment availability. Furthermore, the LTSA guarantees performance and emissions standards, availability targets, and coverage for both scheduled and unscheduled maintenance, ensuring continued operational excellence for the Apex Power Project.

Recommendation

For the above reasons, SCPPA staff recommend that the Purchasing Manager find that the LTSA with GE Vernova International LLC qualifies as a Sole Source as defined in the SCPPA Procurement Code.

Sincerely,

Charles Guss
Senior Asset Manager

I agree with the sole source justification described in this memo.

Aileen Ma
Purchasing Manager
Date: 12/9/2024

RESOLUTION NO. 2024-108

RESOLUTION OF THE BOARD OF DIRECTORS OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY APPROVING AND AUTHORIZING EXECUTION OF AMENDMENT 3 TO THE LONG-TERM SERVICE AGREEMENT BETWEEN SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY AND GE VERNOVA INTERNATIONAL LLC

WHEREAS, the Southern California Public Power Authority ("SCPPA" or "the Authority") is a public entity duly organized and existing under the Joint Exercise of Powers Act (Cal. Government Code sec. 6500 *et seq.*), pursuant to a Joint Powers Agreement ("JPA") entered into by and among the Cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon and the Imperial Irrigation District (each, a "Member"), with authority to engage in various activities supportive of the Members' electric utilities; and

WHEREAS, the Authority is the owner of the Apex Generating Station Project ("Apex") in Las Vegas, Nevada, and is a party to a LongTerm Services Agreement with GE Vernova International LLC ("GE") for the maintenance of the GE generating station equipment (as amended, the "LTSA"); and

WHEREAS, without amendment, the LTSA will expire after 112,000 fire hours, which is projected to be in the second quarter of 2025; and

WHEREAS, as SCPPA's agent for Apex, the Los Angeles Department of Water & Power ("LADWP") has determined that the LTSA continues to be needed beyond the second quarter of 2025 to provide for the planned replacement of combustion turbine, steam turbine, and generator parts along with installation services for these parts and monitoring and diagnostic services; and

WHEREAS, LADWP has negotiated the terms of Amendment 3 to the LTSA ("Amendment 3") with GE which would, among other things, extend the term of the LTSA; and

WHEREAS, Section 2(b)(5) of the SCPPA Procurement Code provides an exemption to Sealed Competitive Bidding for contracts where the SCPPA Purchasing Manager determines in accordance with the Procurement Code and the SCPPA Solicitation and Contract Management Procedure that only a Sole Source of supply is available for a good or service; and

WHEREAS, GE is the original equipment manufacturer for parts required to operate the turbines at Apex, and the SCPPA Purchasing Manager, with the concurrence of the Executive Director, has determined that GE continues to be a sole source for the goods and services to be provided under the LTSA; and

WHEREAS, the Board of Directors' approval of Amendment 3 is categorically exempt from CEQA as the proposed GE repairs to existing facilities fall under CEQA Guideline Section 15301 (minor alteration to an existing facility used to provide electric power, involving negligible or no expansion of use) and Section 15302 (replacement or reconstruction of existing utility systems and/or facilities involving negligible or no expansion of capacity).

NOW, THEREFORE, THE BOARD OF DIRECTORS DOES FIND AND RESOLVE AS FOLLOWS:

1. Amendment 3 to the LTSA is hereby approved.

2. The Executive Director or his designee is hereby authorized and directed to execute and deliver Amendment 3 to the LTSA, with such changes, insertions, and omissions as shall be approved by the Executive Director or his designee (such approval to be conclusively evidenced by her or his execution and delivery thereof), and each of the Secretary and any Assistant Secretary is hereby authorized to attest to such signature.

3. The Executive Director and other officers of the Authority are hereby authorized and directed to execute and deliver any and all other 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 (including, but not limited to, making such changes to the agreements, documents, and instruments referred to in this Resolution if such changes are determined by the President, Vice President, or Executive Director to be necessary or advisable).

Each reference in this Resolution to the President, Vice President, Secretary, Assistant Secretary, or Executive Director shall refer to the person holding such office or position, as applicable, at the time of 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.

4. The actions approved by this Resolution are categorically exempt from CEQA under CEQA Guideline Section 15301 (minor alteration to an existing facility used to provide electric power, involving negligible or no expansion of use) and Section 15302 (replacement or reconstruction of existing utility systems and/or facilities involving negligible or no expansion of capacity).

5. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority this 19th day of December 2024.

TIKAN SINGH
PRESIDENT
Southern California Public
Power Authority

ATTEST:

DANIEL E GARCIA
ASSISTANT SECRETARY
Southern California Public
Power Authority

SCPPA
Southern California Public Power Authority

AGENDA ITEM STAFF REPORT

MEETING DATE: December 19, 2024 **RESOLUTION NUMBER:** 2024-109

SUBJECT: Refinancing of the Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission System Project)

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: Anaheim, Burbank, Glendale, LADWP, Pasadena, and Riverside

Other Members Potentially Participating: None

Approved by Executive Director: Signed by: DAE0F3A6ECDE496...

RECOMMENDATION:

Adopt a Resolution authorizing the issuance of refunding revenue bonds to refinance the Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission System Project) and the execution and delivery of various agreements and documents relating to the issuance of the refunding revenue bonds.

BACKGROUND:

SCPPA currently has $89,480,000 in outstanding Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C. These bonds represent the final outstanding bonds for the Southern Transmission System (STS) Project and have an optional redemption date of January 1, 2025 and a final maturity of July 1, 2027.

The SCPPA Member participants of the STS Project are Anaheim, Burbank, Glendale, LADWP, Pasadena, and Riverside (Project Participants).

DISCUSSION:

The financing plan anticipates issuing fixed rate tax-exempt refunding revenue bonds to refinance the outstanding 2015 Subordinate Refunding Series C bonds for debt service savings and amortizing the bonds to the same final maturity of July 1, 2027.

On September 19, 2024, the Board of Directors adopted Resolution No. 2024-095 authorizing the preparation of all documents necessary for the refunding of the outstanding 2015 Subordinate Refunding Series C bonds. These documents have been prepared.

Resolution No. 2024-109, attached, will authorize the issuance of the refunding revenue bonds and the execution and delivery of the various agreements and documents related to the refunding revenue bonds, including those attached to this report. Due to market volatility, the Resolution also includes a provision whereby the refunding shall result in net debt service savings. The refunding will not proceed if there will be a dissaving as a result of a rise in interest rates at the time of pricing. The Finance Committee recommended approval of the Resolution at the December 2, 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 and Disclosure Counsel, Nixon Peabody LLP serving as Special Tax Counsel, and PFM Financial Advisors LLC serving as Municipal Advisor. An additional member of the financing team is US Bank, serving as Trustee/Paying Agent. Fees for services will be paid from bond proceeds.

  Per SCPPA's Policy for Financing and Selection of the Financing Team, SCPPA may issue refunding revenue bonds on a negotiated or competitive basis. Due to the size and tenor of the bonds, the bonds will be priced on a competitive basis. The winning underwriter will be the bidder that provides the highest responsible bid for the bonds producing the lowest true interest cost.

- **Environmental Review**

  The proposed action is exempt from California Environmental Quality Act as it is not a project as defined under Section 15378 of the State CEQA Guidelines, as it does not have the potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment.

- **SCPPA's Authority:**

  The refinancing of the STS 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 interest rates as of November 25, 2024, the net present value savings were approximately $2.4 million (or $2.7 million in cashflow savings), which was approximately 2.67% of refunded par. Actual savings will depend on market conditions at the time of bond pricing.

Exhibit A of the Resolution No. 2024-109 provides good faith estimates of various financial information regarding the refunding revenue bonds to be issued, which include principal amount, true interest cost, finance charge, amount of proceeds, and total payment.

ATTACHMENT:

1. Resolution No. 2024-109
2. Thirty-First Supplemental Indenture of Trust
3. Indenture of Trust
4. Continuing Disclosure Undertaking
5. Preliminary Official Statement
6. Notice of Intention to Sell Bonds
7. Notice Inviting Bids and Official Bid Form

[Project Vote: Anaheim, Burbank, Department of Water and Power of The City of Los Angeles, Glendale, Pasadena and Riverside]

RESOLUTION NO. 2024-109

RESOLUTION RELATING TO THE SOUTHERN TRANSMISSION PROJECT: AUTHORIZING (I) THE ISSUANCE OF REFUNDING BONDS FOR THE SOUTHERN TRANSMISSION PROJECT; (II) THE EXECUTION AND DELIVERY OF (A) A SUBORDINATE INDENTURE OF TRUST AUTHORIZING THE ISSUANCE OF TRANSMISSION PROJECT REVENUE BONDS, 2025 SUBORDINATE REFUNDING SERIES A; (B) A SUPPLEMENTAL INDENTURE OF TRUST RELATING TO SUCH BONDS; AND (C) A CONTINUING DISCLOSURE UNDERTAKING; (III) THE DELIVERY OF A PRELIMINARY OFFICIAL STATEMENT AND THE EXECUTION AND DELIVERY OF AN OFFICIAL STATEMENT; (IV) PUBLICATION OF A NOTICE OF INTENTION TO SELL BONDS AND A NOTICE INVITING BIDS AND OFFICIAL BID FORM; (V) CERTAIN RELATED ACTIONS; AND (VI) THE OFFICERS AND OFFICIALS OF THE AUTHORITY TO DO ALL OTHER THINGS DEEMED NECESSARY OR ADVISABLE

WHEREAS, the Authority has heretofore financed and refinanced costs of Authority capacity relating to capital improvement of the Southern Transmission Project through the issuance of notes and bonds, including the Authority's Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission Project) (the "Refunded Bonds"); and

WHEREAS, the Finance Committee of the Authority recommended that the Authority, if approved by the Board of Directors, proceed with the refunding of the outstanding Refunded Bonds by issuing its Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (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 Southern Transmission Project, the Project Participants 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;

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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 and the Chief Financial and Administrative Officer of the Authority (each, an "Authorized Representative") is hereby authorized to execute and deliver a Thirty-First Supplemental Indenture of Trust relating to the Bonds, from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"), amending and supplementing the Indenture of Trust, by and between the Authority and the Trustee (as successor trustee), dated as of May 1, 1983, relating to the Southern Transmission Project (as supplemented and amended, the "Senior Indenture"), in the form on file with an Assistant Secretary of the Authority, with such changes, insertions and omissions (subject to Paragraph 8 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 Thirty-First Supplemental Indenture of Trust, as executed and delivered, is hereinafter referred to as the "Supplemental Indenture." Proceeds of the Bonds shall be used primarily to refund all or a portion of the Refunded Bonds. The 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.

2. Each Authorized Representative is hereby authorized to execute and deliver an Indenture of Trust relating to the Bonds, from the Authority to the Trustee, in the form on file with an Assistant Secretary of the Authority, with such changes, insertions and omissions (subject to Paragraph 8 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 Indenture of Trust, as executed and delivered, is hereinafter referred to as the "Indenture." Proceeds of the Bonds shall be used primarily to refund all or a portion of the Refunded Bonds. The 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 Senior Indenture, the Indenture and the 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 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 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 any Project Participant (as defined in the Indenture) 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 any 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.

3. Each Authorized Representative is hereby authorized to execute and deliver the Continuing Disclosure Undertaking (the "Undertaking"), in substantially the form on file with the Authority, with such changes, insertions and omissions as shall be approved by said Authorized Representative (such approval to be conclusively evidenced by such Authorized Representative's execution and delivery thereof). The form of the Undertaking is hereby made a part of this Resolution as though set forth in full herein and the same hereby is approved.

4. 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 distribution (including by electronic delivery) of the Preliminary Official Statement to potential purchasers of the Bonds is hereby authorized as set forth in Section 6.

5. 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 successful bidder for use in connection with the sale of the Bonds. The successful bidder is hereby

authorized to distribute the Official Statement and any such amendment or supplement thereto to the purchasers of the Bonds.

6. Bids for the purchase of the Bonds shall be received by an Authorized Representative at the time and place determined as provided in the Notice of Intention to Sell Bonds, the Notice Inviting Bids and the Official Bid Form as hereinafter approved.

The form of Notice of Intention to Sell Bonds 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. Each Authorized Representative is further authorized and directed to publish a Notice of Intention to Sell Bonds by one insertion in The Bond Buyer, or another financial publication generally circulated throughout California, prior to the date of receiving proposals for the purchase of the Bonds.

Each Authorized Representative is authorized and directed to cause to be provided or furnished to prospective bidders, upon their request, the Preliminary Official Statement, the Notice Inviting Bids, the Official Bid Form and a reasonable number of copies of this Resolution, the Senior Indenture, the Indenture and the Supplemental Indenture.

The form of Notice Inviting Bids and Official Bid Form 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. Each Authorized Representative is authorized and directed to cause to be furnished to prospective bidders, upon their request, a reasonable number of copies of the Notice Inviting Bids and Official Bid Form. Each Authorized Representative is further authorized and directed, after any proposal for the purchase of the Bonds has been accepted by an Authorized Representative, and after the final Official Statement has been prepared, to cause to be furnished to the successful bidder for use in connection with the resale of the Bonds, such number of copies of the final Official Statement as may be reasonably required.

Each Authorized Representative may withdraw or modify the Notice Inviting Bids, the Official Bid Form and/or the Notice of Intention to Sell Bonds at any time by notice announced through the Parity® electronic bid submission system of Ipreo or other means determined by the Authorized Representative to be reasonably calculated to reach potential bidders for the Bonds. If an Authorized Representative should withdraw the Notice Inviting Bids and the Official Bid Form or the Notice of Intention to Sell Bonds at any time before all of the Bonds are awarded, and should at a later date determine that it is desirable to receive bids for all or a portion of the Bonds, then each Authorized Representative is hereby authorized to redistribute the Notice Inviting Bids and the Official Bid Form and republish the Notice of Intention to Sell Bonds with such modifications or revisions as are approved by the Authorized Representative.

Each Authorized Representative is hereby authorized to award the purchase of the Bonds to the bidder that provides the highest responsible bid for the Bonds producing the lowest true interest cost to the Authority as provided in the Notice Inviting Bids. The refunding shall result in net debt service savings to the Authority on a net present value basis, using the Bonds true interest cost as the discount rate. Each Authorized Representative is hereby further authorized to reject any and all bids as he or she deems appropriate and to waive any irregularity or informality in any bid or bids.

7. The refunding of all or a portion of the Refunded Bonds as provided for in the 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.

8. Each Authorized Representative is hereby authorized to determine and undertake, in connection with the execution and delivery of the Indenture, the Supplemental Indenture, the Continuing Disclosure Undertaking and the Notice Inviting Bids, the preparation and publication of the Notice of Intention to Sell Bonds and the sale of the Bonds, and in consultation with the representative of Project Participants on the Authority's Finance Committee, the following:

(i) the principal amount of the Bonds, which Bonds in the aggregate shall not exceed $100,000,000 principal amount;

(ii) if less than all of the Refunded Bonds are to be refunded by the Bonds, the principal amounts and maturities of such bonds to be refunded;

(iii) in connection with the refunding of the Refunded Bonds, any transfers required or permitted from any funds or accounts created under (a) the Senior Indenture, (b) the Indenture of Trust, dated as of March 1, 2015, by and between the Authority and the Trustee, relating to the Refunded Bonds (including, but not limited to, the transfer of any moneys in the 2015 Series C Payment Account established thereunder), (c) any other indenture of trust relating to the Southern Transmission Project or (d) Board Resolution 2016-084 adopted on August 18, 2016 relating to the Project Stabilization Fund;

(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 4.50% per annum;

(vi) the maturity dates for the Bonds, with the final maturity thereof being no later than July 1, 2027;

(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 and any other available moneys; and

(xiii) the initial escrow securities, if any, to be deposited in the Escrow Funds for the Refunded Bonds under the Supplemental Indenture.

9. The Board hereby determines pursuant to Section 511.2 of the Senior Indenture that moneys on deposit in the General Reserve Fund may be applied to or set aside for any of the purposes specified in said Section 511.2 (including any lawful purpose of the Authority related to the Southern Transmission Project), which purpose or purposes shall be evidenced by a certificate of an Authorized Representative. In connection with the application or setting aside of any such moneys, each Authorized Representative, the Secretary and any Assistant Secretary of the Authority is hereby authorized on behalf of the Authority to take such other actions as any of them may deem necessary or appropriate.

10. 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 successful bidder for the Bonds; and any such action previously taken is hereby ratified, confirmed and approved.

11. 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 $80,000, (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 $160,000, 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 $50,000.

12. 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 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.

13. The following are hereby designated as Project Agreements under the Senior Indenture and the Transmission Service Contracts (as defined in the Senior Indenture): (a) the Indenture; (b) the Supplemental Indenture; and (c) the Continuing Disclosure Undertaking.

14. Each Authorized Representative, the Secretary, any Assistant Secretary of the Authority and any representative of the Department of Water and Power of The City of Los

Angeles, as agent of the Authority, is hereby authorized to cause the Trustee to transfer moneys as contemplated by the Supplemental Indenture (including, but not limited to, the transfer of released moneys, if any, in the 2015 Series C Payment Account relating to the Refunded Bonds).

15. 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 Senior Indenture, the Indenture and every other subordinate indenture of trust of the Authority relating to the Southern Transmission Project for the purpose of taking any and all required or permitted actions in connection with the issuance and delivery of the Bonds.

16. 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 Senior Indenture, the Indenture, the Supplemental Indenture 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 Authority, the Project Participants 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.

17. 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.

18. 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.

19. This Resolution shall become effective immediately.

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THE FOREGOING RESOLUTION NO. 2024-109 is approved and adopted by the Authority this 19th day of December, 2024.

____

TIKAN SINGH
PRESIDENT
Southern California Public
Power Authority

ATTEST:

____

DANIEL E GARCIA
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 $73,290,000 (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 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 2.69%. 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 $662,370.00.

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 $75,554,982.40.

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 $79,357,308.33.

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.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

to

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION

as Trustee

Thirty-First Supplemental Indenture of Trust

Dated as of [_____] 1, 2025

(Southern Transmission Project)

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THIRTY-FIRST SUPPLEMENTAL INDENTURE OF TRUST

THIS THIRTY-FIRST SUPPLEMENTAL INDENTURE OF TRUST (this "Thirty-First Supplemental Indenture of Trust") dated as of [_____] 1, 2025, 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, duly organized and existing under and by virtue of the laws of the United States of America and authorized to accept and execute trusts of the character herein set out, with a corporate trust office located at 633 West Fifth Street, 24th Floor, Los Angeles, California 90071, 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 May 1, 1983, from the Authority to a predecessor of the Trustee, to provide for, among other things, the securing of Notes, Bonds and subordinate bonds (as supplemented and amended, the "Indenture of Trust"); and

WHEREAS, the Authority desires to issue $[_____________] aggregate principal amount of Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "2025 Series A Subordinate Bonds") in order to provide funds to redeem the Refunded Bonds (as defined herein), which bonds were issued in 2015 to refinance a portion of the cost of acquisition of capacity relating to a capital improvement of the Southern Transmission System by refunding the Authority's Transmission Project Revenue Bonds, 2008 Subordinate Series B (Southern Transmission Project); and

WHEREAS, the 2025 Series A Subordinate Bonds will be issued and secured under an Indenture of Trust, dated as of [_____] 1, 2025, from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "2025 Series A Subordinated Indenture"); and

WHEREAS, the Authority hereby finds and determines that the refunding transaction provided for in this Thirty-First Supplemental Indenture of Trust, the 2025 Series A Subordinated Indenture and the related financial arrangements will result in significant public benefits; and

WHEREAS, in accordance with the Indenture of Trust, the Authority has created herein the 2025 Series A Subordinate Bonds Redemption Fund (as defined herein) and caused to be deposited therein moneys to effect such refunding; and

WHEREAS, in connection with the issuance of the 2025 Series A Subordinate Bonds, the Authority desires to amend the Indenture of Trust in certain respects; and

WHEREAS, the Authority has determined that all acts and things have been done and performed which are necessary to make this Thirty-First Supplemental Indenture of Trust a valid and binding agreement and supplement to the Indenture of Trust;

NOW, THEREFORE, KNOW ALL PERSONS BY THESE PRESENTS, THIS THIRTY-FIRST SUPPLEMENTAL INDENTURE OF TRUST WITNESSETH:

That, in consideration of the premises, the acceptance by the Trustee of the trusts hereby created and originally created by the Indenture of Trust, the mutual covenants herein contained and the purchase and acceptance of the 2025 Series A Subordinate Bonds 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 applicable) of, and interest on, the 2025 Series A Subordinate Bonds 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 of Trust 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. Supplemental Indenture of Trust. This Thirty-First Supplemental Indenture of Trust is supplemental to the Indenture of Trust.

102. Authority for this Thirty-First Supplemental Indenture of Trust. This Thirty-First Supplemental Indenture of Trust is entered into in accordance with Article X of the Indenture of Trust.

103. Definitions.

(1) Except as provided by this Thirty-First Supplemental Indenture of Trust, all terms which are defined in Section 101 of the Indenture of Trust shall have the same meanings in this Thirty-First Supplemental Indenture of Trust.

(2) In this Thirty-First Supplemental Indenture of Trust:

Refunded Bonds shall mean all of the outstanding 2015 Series C Subordinate Bonds in the aggregate principal amount of $89,480,000 and maturing on July 1, 2025 through 2027, inclusive.

Subordinate Trustee shall mean the Trustee under the 2015 Series C Subordinated Indenture and/or the Trustee under the 2025 Series A Subordinated Indenture.

2015 Series C Subordinated Indenture shall mean the Indenture of Trust, dated as of March 1, 2015, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee, as from time to time amended or supplemented in accordance with the terms thereof.

2025 Series A Subordinate Bonds shall mean the Authority's Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project), authorized by the 2025 Series A Subordinated Indenture.

2025 Series A Subordinate Bonds Redemption Fund shall have the meaning ascribed thereto in Section 301 of this Thirty-First Supplemental Indenture of Trust.

2025 Series A Subordinated Indenture shall mean the Indenture of Trust, dated as of [_____] 1, 2025, from the Authority to U.S. Bank Trust Company, National Association, as trustee, as from time to time amended or supplemented in accordance with the terms thereof.

ARTICLE II

APPLICATION OF PROCEEDS; TRANSFERS

201. Application of Proceeds of 2025 Series A Subordinate Bonds; Transfer and Application of Other Amounts.

(1) Simultaneously with the delivery of the 2025 Series A Subordinate Bonds, of the $[__________] proceeds of the 2025 Series A Subordinate Bonds (representing the par amount of the 2025 Series A Subordinate Bonds, plus original issue premium of $[__________], and less Underwriters' discount of $[_________]), the amount of $[____________] shall be transferred to the Subordinate Trustee, as trustee for the Refunded Bonds, for deposit in the 2025 Series A Subordinate Bonds Refunding Redemption Fund, and the Subordinate Trustee shall so deposit such moneys in the 2025 Series A Subordinate Bonds Redemption Fund for the redemption of the Refunded Bonds.

(2) Simultaneously with the delivery of the 2025 Series A Subordinate Bonds, the balance of the proceeds of the 2025 Series A Subordinate Bonds in the amount of $[__________] shall be transferred to the Subordinate Trustee, as trustee for the 2025 Series A Subordinate Bonds, for deposit in the 2025 Series A Costs of Issuance Account in the 2025 Series A Issue Fund for the 2025 Series A Subordinate Bonds, and the Subordinate Trustee shall so deposit such moneys in the 2025 Series A Costs of Issuance Account in the 2025 Series A Issue Fund for the 2025 Series A Subordinate Bonds, to be applied to pay costs of issuance of the 2025 Series A Subordinate Bonds

(3) Simultaneously with the delivery of the 2025 Series A Subordinate Bonds, the amount of $[_____], representing the accrued debt service in the 2015 Series C Payment Account in the 2015 Series C Issue Fund under the 2015 Series C Subordinated Indenture with respect to the Refunded Bonds, as specified in writing by the President, Vice President or Executive Director of the Authority, shall be transferred by the Subordinate Trustee, as trustee for the Refunded Bonds, for deposit in the 2025 Series A Subordinate Bonds Redemption Fund, and the Subordinate Trustee shall so deposit such amount in the 2025 Series A Subordinate Bonds Redemption Fund.

(4) Simultaneously with the delivery of the 2025 Series A Subordinate Bonds, the amount of $[____], representing the balance on deposit in the 2015 Series C Remainder Account in the 2015 Series C Issue Fund under the 2015 Series C Subordinated Indenture with respect to the Refunded Bonds, as specified in writing by

the President, Vice President or Executive Director of the Authority, shall be transferred to the Subordinate Trustee, as trustee for the Refunded Bonds, for deposit in the 2025 Series A Subordinate Bonds Redemption Fund, and the Subordinate Trustee shall so deposit such amount in the 2025 Series A Subordinate Bonds Redemption Fund.

ARTICLE III

2025 SERIES A SUBORDINATE BONDS REDEMPTION FUND

301. Establishment of 2025 Series A Subordinate Bonds Redemption Fund. There is hereby created and established with the Subordinate Trustee, a special and irrevocable trust fund under the Indenture designated the 2025 Series A Subordinate Bonds Redemption Fund to be held by the Subordinate Trustee separate and apart from all other funds of the Authority or the Subordinate Trustee. Amounts on deposit in the 2025 Series A Subordinate Bonds Redemption Fund shall irrevocably be applied solely for the purposes and on the terms and conditions set forth in this Thirty-First Supplemental Indenture. The Subordinate Trustee shall have no claim against, or right to payment from, any moneys or investments in the 2025 Series A Subordinate Bonds Redemption Fund.

302. Use and Investment of Moneys on Deposit in 2025 Series A Subordinate Bonds Redemption Fund. The Subordinate Trustee acknowledges receipt of the moneys (i.e., $[_____], being the sum of a portion of the proceeds of the 2025 Series A Subordinate Bonds in the amount of $[_____], accrued debt service on the Refunded Bonds in the amount of $[_____] and a transfer from the 2015 Series C Remainder Account in the amount of $[_____]), to be deposited in the 2025 Series A Subordinate Bonds Redemption Fund as provided in Section 201 hereof, which moneys the Subordinate Trustee shall hold uninvested as cash.

303. Payment and Redemption of Refunded Bonds.

(1) The Subordinate Trustee shall apply amounts in the 2025 Series A Subordinate Bonds Redemption Fund to pay on [_____], 2025, the redemption date for the Refunded Bonds, the Redemption Price of, and accrued interest on, the Refunded Bonds called for redemption on such date. The Subordinate Trustee acknowledges that (a) it has mailed a notice, in substantially the form as set forth in Exhibit A, not less than 30 days nor more than 60 days before such redemption date, to the registered owners of the Refunded Bonds, (b) it has given such notice to the Information Services and the Securities Depository (as defined in the 2015 Series C Subordinated Indenture and as provided in Section 404 thereof) in accordance with the requirements of the 2015 Series C Subordinated Indenture, and (c) it has provided a copy of such notice by electronic means of communication to the MSRB through EMMA.

(2) The owners of the Refunded Bonds shall have an exclusive lien on the moneys and in the 2025 Series A Subordinate Bonds Redemption Fund until such moneys are used and applied as provided in this Thirty-First Supplemental Indenture of Trust.

304. Termination of Obligation. As provided in 2015 Series C Subordinate Indenture, upon the transfer and deposit of the moneys described in Section 201 hereof in the 2025 Series A Subordinate Bonds Redemption Fund, except for the rights of the owners of the Refunded Bonds to payments from the 2025 Series A Subordinate Bonds Redemption Fund, the owners of the Refunded Bonds shall cease to be entitled to any lien, benefit or security under the Indenture or the 2015 Series C Subordinate 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 Subordinate 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 2015 Series C Subordinate Indenture until the Refunded Bonds have been paid.

ARTICLE IV

AMENDMENTS TO CERTAIN PROVISIONS OF THE INDENTURE OF TRUST

401. Indenture of Trust to Remain in Effect. Except as amended and supplemented by this Thirty-First Supplemental Indenture of Trust, the Indenture of Trust shall remain in full force and effect.

(1) Additions to Section 101 of the Indenture of Trust. The following definitions shall be added to Section 101 of the Indenture of Trust:

2025 Series A Accrued Debt Service shall have the meaning ascribed thereto in the 2025 Series A Subordinated Indenture.

2025 Series A Charges Account shall mean the account so designated in the 2025 Series A Subordinated Indenture.

2025 Series A Payment Account shall mean the account so designated in the 2025 Series A Subordinated Indenture.

2025 Series A Pledged Revenues Account shall mean the account so designated in the 2025 Series A Subordinated Indenture.

2025 Series A Remainder Account shall mean the account so designated in the 2025 Series A Subordinated Indenture.

2025 Series A Reserve Account shall mean the account so designated in the 2025 Series A Subordinated Indenture.

2025 Series A Subordinated Indenture shall have the meaning ascribed thereto in the Thirty-First Supplemental Indenture of Trust.

2025 Series A Subordinated Indenture Requirements shall mean, with respect to any period, all amounts required under the 2025 Series A Subordinated Indenture to be deposited (other than from the 2025 Series A Remainder Account) into the 2025 Series A

Payment Account, the 2025 Series A Reserve Account and the 2025 Series A Charges Account during such period to provide for, among other things, 2025 Series A Accrued Debt Service.

(2) Amendment to Section 101 of the Indenture of Trust. The following definition contained in Section 101 of the Indenture of Trust shall be amended to read as follows:

Revenues shall mean (i) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to Authority Capacity or to the payment of the costs thereof received or to be received by the Trustee under the Transmission Service Contracts or under any other contract for the sale by the Authority of Authority Capacity or any part thereof or any contractual arrangement with respect to the use of Authority Capacity or any portion thereof or the services or capacity thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to Authority Capacity, (iii) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Indenture of Trust and required to be paid into the Revenue Fund, (iv) interest received on any moneys or securities held pursuant to the 2025 Series A Subordinated Indenture, and required by their terms to be paid into the Revenue Fund, (v) amounts received by or on behalf of the Authority pursuant to any Parity Swap, (vi) amounts received by or on behalf of the Authority pursuant to any subordinate swap agreement or similar agreement that provides therein (including in any schedule or attachment thereto) that payments received by or on behalf of the Authority pursuant thereto shall constitute Revenues under the Indenture of Trust, and (vii) amounts received by or on behalf of the Authority pursuant to any Cap Agreement.

(3) Amendment to Subsections 4 and 5 of Section 511 of the Indenture of Trust. Subsections 4 and 5 of Section 511 of the Indenture of Trust shall be amended to read as follows:

4. The Authority will make provisions in the Annual Budget for each Fiscal Year for all amounts required to provide for the 2025 Series A Subordinated Indenture Requirements, and all other amounts required to be provided for from Available Revenues.

5. The Authority hereby determines that, on or before the last business day of each calendar month, Available Revenues, to the extent required to provide for the 2025 Series A Subordinated Indenture Requirements for such month, shall be applied by the transfer thereof from the General Reserve Fund to the trustee for the 2025 Series A Subordinated Indenture, for deposit in the 2025 Series A Pledged Revenues Account. Such determination need not be evidenced by a certificate of an Authorized Authority Representative, Section 511(2) hereof notwithstanding. All Available Revenues so applied shall be free and clear of the lien and pledge of the Indenture of Trust.

ARTICLE V

MISCELLANEOUS

501. Indenture of Trust to Remain in Effect. Except as amended and supplemented by this Thirty-First Supplemental Indenture of Trust, the Indenture of Trust shall remain in full force and effect.

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

503. Performance of Duties; No Claim Against 2025 Series A Subordinate Bonds Redemption Fund. The Trustee (including in its capacity as the Subordinate Trustee) agrees to perform the duties set forth herein. The Trustee and the Subordinate Trustee shall have no claim against, or right to payment from, any moneys or investments in the 2025 Series A Subordinate Bonds Redemption Fund.

504. Severability. If any one or more of the covenants or agreements provided in this Thirty-First Supplemental Indenture of Trust on the part of the Authority or the Trustee (including in its capacity as the Subordinate Trustee) to be performed 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 Thirty-First Supplemental Indenture of Trust.

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

[Remainder of page intentionally left blank.]

IN WITNESS WHEREOF, Southern California Public Power Authority has caused these presents 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 this Thirty-First Supplemental Indenture of Trust to be signed in its name and on its behalf (and on behalf of the Subordinate Trustee) by its duly authorized officer, all as of the 1st day of [_____], 2025.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

[Authority Seal]

By__________________________________
President

Attest

____
Assistant Secretary

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

By__________________________________
Authorized Officer

EXHIBIT A

CONDITIONAL NOTICE OF FULL REDEMPTION
of
$89,480,000
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Transmission Project Revenue Bonds,
2015 Subordinate Refunding Series C
(Southern Transmission Project)
(Date of Issue: March 25, 2015)

Notice is hereby given in the name of Southern California Public Power Authority (the "Authority") to the holders of the $89,480,000 outstanding principal amount of Southern California Public Power Authority Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission Project) (the "2015 Series C Subordinate Bonds") issued on March 25, 2015 that the Authority has elected to redeem all of the outstanding 2015 Series C Subordinate Bonds, as more fully identified below, on [_____], 2025 (the "Redemption Date"), at a redemption price equal to 100% of the principal amount thereof plus accrued interest to the Redemption Date (the "Redemption Price").

Refunded 2015 Series C Subordinate Bonds

Maturity Date (July 1)	Outstanding Principal Amount	Interest Rate	CUSIP
2025	$ 200,000	4.00%	842477UC3
2025	28,190,000	5.00	842477TY7
2026	610,000	4.00	842477UD1
2026	29,195,000	5.00	842477TZ4
2027	10,225,000	4.00	842477UE9
2027	21,060,000	5.00	842477UA7

On the Redemption Date, if sufficient moneys are then available for such redemption, the Redemption Price of the 2015 Series C Subordinate Bonds will become due and payable, and from and after the Redemption Date interest shall cease to accrue. All such 2015 Series C Subordinate Bonds shall be surrendered at the address of the Trustee specified below.

The source of funds to be used for such redemption will include proceeds of refunding revenue bonds to be issued by the Authority. This Notice is subject to the availability of such funds for such purpose, and this Notice will be withdrawn if such refunding revenue bonds are not issued on or prior to the Redemption Date and the Authority is unable to deposit with the Trustee not later than the opening of business on the Redemption Date moneys sufficient to redeem the 2015 Series C Subordinate Bonds on the Redemption Date. If this Notice is withdrawn by the Authority, this Notice shall be of no force or effect, and none of the 2015 Series C Subordinate Bonds shall be redeemed pursuant to this Notice.

Payment of the Redemption Price of the 2015 Series C Subordinate Bonds called for redemption will be made upon presentation and surrender thereof on and after the Redemption Date (*i.e.*, [____], 2025) at the following address:

U. S. Bank Trust Company, National Association
Global Corporate Trust Services
111 Fillmore Avenue E
St. Paul, MN 55107
1-800-934-6802

Bondholders presenting their 2015 Series C Subordinate Bonds in person for the same day payment must surrender their 2015 Series C Subordinate Bonds by 1:00 p.m., CST, on the Redemption Date and a check will be available for pickup after 2:00 p.m. Checks not picked up by 4:30 p.m., CST, will be mailed to the bondholders by first class mail.

If payment of the Redemption Price is to be made to the registered owner of the 2015 Series C Subordinate Bond, such holder is not required to endorse the 2015 Series C Subordinate Bond to collect the Redemption Price.

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.

For a list of redemption requirements please visit our website at www.usbank.com/corporatetrust and click on the "Bondholder Information" link for redemption instructions. You may also contact our Bondholder Communications team at 1-800-934-6802 Monday through Friday from 8 a.m. to 6 p.m. CST.

The CUSIP number or numbers have been assigned by CUSIP Global Services, managed by Standard & Poor's Financial Services LLC on behalf of The American Bankers Association and are included solely for the convenience of the bondholders. Neither the Authority nor the Trustee shall be responsible for the selection or use of the CUSIP number or numbers nor is any representation made as to the correctness of such number or numbers herein or on the 2015 Series C Subordinate Bonds.

Dated: __________, 2025

U.S. Bank Trust Company, National Association, as Trustee

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

to

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

INDENTURE OF TRUST

Dated as of [_____] 1, 2025

Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

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INDENTURE OF TRUST

THIS INDENTURE OF TRUST dated as of [_____] 1, 2025 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"), with a corporate trust office located at 633 West Fifth Street, 24th Floor, Los Angeles, California 90071;

W I T N E S S E T H :

WHEREAS, the Authority is authorized pursuant to the provisions relating to joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), to acquire rights to capacity in a project within or without the State of California to provide for, among other things, the transmission of electric energy, to enter into agreements with respect to any matters relating to the acquisition of the rights to capacity in such project, and to finance its interest in such project through the issuance of bonds, notes and other evidences of indebtedness under the Act; and

WHEREAS, the Project Participants (terms not otherwise defined in this preamble will have the respective meanings given to them in this Indenture of Trust) have assigned their rights to capacity in the Transmission Project to the Authority pursuant to the Agreements for the Acquisition of Capacity; and

WHEREAS, the Authority on behalf of the Project Participants has made payments-in-aid of construction for the Transmission Project to Intermountain Power Agency in consideration for the assignment of the rights to capacity in the Transmission Project; and

WHEREAS, the Authority and the Project Participants have entered into the Transmission Service Contracts pursuant to which the Authority sells transmission service utilizing Authority Capacity to the Project Participants; and

WHEREAS, the Authority has heretofore financed and refinanced costs of Authority Capacity through the issuance of notes and bonds under the Senior Indenture and certain subordinate indentures of trust, including the Authority's Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the "2015 Subordinate Refunding Series C Bonds"); and

WHEREAS, the Authority intends to refund and defease the outstanding 2015 Subordinate Refunding Series C Bonds by issuing the Bonds under this Indenture of Trust; and

WHEREAS, the Authority desires to provide for the securing of the Bonds and any Parity Swaps as provided in this Indenture of Trust; and

WHEREAS, the Trustee has accepted the trust created and established by this Indenture of Trust and in evidence thereof has joined in the execution hereof;

NOW, THEREFORE, (i) in consideration of the premises, of the acceptance by the Trustee of the trust hereby created, and of the purchase and acceptance of the Bonds by the Owners thereof; (ii) for other valuable consideration, the receipt of which is hereby acknowledged; (iii) to fix and declare the terms and conditions upon which the Bonds are to be issued, authenticated, delivered, secured and accepted by all persons who shall from time to time be or become Owners thereof; (iv) to secure the payment of all the Bonds at any time issued and Outstanding hereunder and the interest thereon according to their tenor, purport and effect and to secure the payment of all obligations of the Authority under any Parity Swaps; and (v) to secure the performance and observance of all of the covenants, agreements and conditions therein and herein contained, the Authority by these presents does hereby pledge and assign unto the Trustee (including for the benefit of any Parity Swap Providers to the extent provided in Article V of this Indenture of Trust), all right, title and interest in and to the Pledged Revenues and other amounts in the 2025 Series A Issue Fund (as more fully described in Article V of this Indenture of Trust), and any additional property that may from time to time, by delivery or by writing of any kind, be subjected to the lien hereof by the Authority or by anyone on its behalf; and the Trustee is hereby authorized to receive the same at any time as additional security hereunder, subject to such permitted encumbrances under this Indenture of Trust as may be superior (by operation of law or otherwise) to the lien hereof;

To have and hold all of the above, except as otherwise expressly stated herein, for the equal and ratable benefit of any Parity Swap Providers (other than any termination payments to any such Parity Swap Providers) and the Owners from time to time of the Bonds, if any, authenticated hereunder and issued by the Authority and Outstanding without any priority of any one Bond over any other, in each case upon the trusts and subject to the covenants and conditions hereinafter set forth;

PROVIDED, NEVERTHELESS, and these presents are upon the express condition that, if the Authority or its successors or assigns (i) shall well and truly pay or cause to be paid the principal of such Bonds with interest, according to the provisions set forth in the Bonds; (ii) shall provide for the payment or redemption of such Bonds by depositing or causing to be deposited with the Trustee the entire amount of funds or securities requisite for payment or redemption thereof when and as authorized by the provisions hereof; (iii) shall pay or cause to be paid all other sums payable hereunder by the Authority; and (iv) shall pay or cause to be paid to any Parity Swap Providers all sums payable under the Parity Swaps and any such Parity Swaps shall have terminated or expired, then these presents and the estate and rights hereby granted shall cease, terminate and become void. Thereupon the Trustee, on payment of its lawful charges and disbursements then unpaid, on demand of the Authority and upon the payment of the costs and expenses thereof, shall duly execute, acknowledge and deliver to the Authority such instruments of satisfaction or release as may be necessary or proper to discharge this Indenture of Trust (including if appropriate any required discharge of record) and if necessary shall grant, reassign and deliver to the Authority, its successors or assigns, all and singular the property, rights, privileges and interests by it hereby granted, conveyed and assigned, and all substitutes therefor, or any part thereof, not previously disposed of or released as herein provided, otherwise this Indenture of Trust shall be and remain in full force;

NOW, THEREFORE, KNOW ALL PERSONS BY THESE PRESENTS, THIS INDENTURE OF TRUST WITNESSETH:

ARTICLE I

DEFINITIONS AND STATUTORY AUTHORITY

101. Definitions. The following terms shall, for all purposes of this Indenture of Trust, have the following meanings:

Account or Accounts shall mean, as the case may be, each or all of the Accounts established in Section 502.

Accountant's Certificate shall mean a certificate signed by an independent certified public accountant of recognized national standing or a firm of independent certified public accountants or arbitrage rebate specialists (for purposes of Section 1301) of recognized national standing, selected by the Authority.

Act shall mean 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 from time to time, and all laws amendatory or supplemental thereto.

Agent Member shall mean a member of, or participant in, the Securities Depository.

Agreements for the Acquisition of Capacity shall mean the several Agreements for the Acquisition of Capacity between the Authority and the Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms.

Annual Budget shall mean the annual budget, as amended or supplemented, adopted or in effect for a particular Fiscal Year as provided in Section 708.

Authority Capacity shall mean the right of the Authority to capacity in the Transmission Project, pursuant to the Agreements for the Acquisition of Capacity.

Authorized Authority Representative shall mean the President, Vice President or Executive Director of the Authority or any other officer or employee of the Authority (including any officer or employee of the Department of Water and Power of The City of Los Angeles acting as agent for the Authority) authorized to perform specific acts or duties by resolution duly adopted by the Authority.

Authorized Denominations shall mean $5,000 and any integral multiple thereof.

Available Revenues shall have the meaning ascribed thereto in the Senior Indenture.

Board of Directors shall mean the Board of Directors of the Authority, as constituted from time to time, or if said Board of Directors shall be abolished, such other body or bodies succeeding to the principal functions thereof or to whom the power and duties granted or imposed by this Indenture of Trust shall be given by law.

Bond or **Bonds** shall mean any bond or bonds, as the case may be, authenticated and delivered under and pursuant to this Indenture of Trust.

Bond Counsel shall mean a firm or firms of attorneys of recognized national standing in the field of law relating to municipal bonds, selected by the Authority.

Bondowner or **Owner** or **Owner of Bonds** shall mean each person or entity who is the registered owner of any Bond or Bonds.

Bond Registrar shall mean the Trustee and any other bank or trust company organized under the laws of any state of the United States of America, or national banking association, appointed by the Authority to perform the duties of bond registrar enumerated in Sections 304 and 703.

Business Day shall mean a day (a) other than a Saturday, a Sunday or any other day on which banks located in the city in which the principal office of the Trustee or the Paying Agent is located, are required or authorized by law to close, and (b) on which the New York Stock Exchange is not closed.

Code shall mean the Internal Revenue Code of 1986.

Costs of Issuance shall mean any costs or expenses paid or incurred in connection with the issuance and delivery of the Bonds (and such other costs or expenses as the Authority shall direct in writing to the Trustee), including but not limited to fees and expenses of the Trustee and its counsel, initial fees and expenses of the Paying Agent and its counsel, printing costs, word processing costs, costs and fees relating to any bond insurance policy and any Reserve Account Policy, initial fees and expenses of Bond Counsel and other legal fees and expenses, rating agency fees, accounting fees and other expenses incurred by the Authority and fees payable to any other consultants or experts retained in connection with such issuance and delivery.

Debt Service shall mean, with respect to any period, an amount equal to the sum of (i) interest accruing during such period on the Outstanding Bonds, and (ii) that portion of each Principal Installment of the Outstanding Bonds that would become due during such period if such Principal Installment were deemed to become due daily in equal amounts from the next preceding Principal Installment due date for the Bonds (or, if there shall be no such preceding Principal Installment due date, from a date one year preceding the due date of such Principal Installment or the date of initial issuance and delivery of the Bonds, whichever is later). Such interest and Principal Installment for the Bonds shall be calculated on the assumption that no Bonds Outstanding on the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof.

Defeasance Obligations shall mean:

(i) non-callable, direct obligations of the United States of America, obligations fully and unconditionally guaranteed as to payment of principal and interest by the United States of America including, but not limited to, the interest components of Resolution Funding Corporation securities and obligations of the United States Agency for International Development, as well as non-callable, senior debt obligations of the Federal National Mortgage Association, the Federal Home Loan Mortgage Corporation, the Federal Home Loan Bank System and the Federal Farm Credit System (collectively, "Government Obligations"); or

(ii) any bonds or other obligations of any state of the United States of America or of any agency, instrumentality or local governmental unit of any such state which are not callable at the option of the obligor prior to maturity or as to which irrevocable instructions have been given by the obligor to call on the date specified in the notice and (a) rated no lower than the then-current rating on direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America (or by an agency thereof to the extent such obligations are backed by the full faith and credit of the United States of America), or (b)(1) which are fully secured as to principal and interest and redemption premium, if any, by a fund consisting only of cash and/or Government Obligations, which fund may be applied only to the payment of such principal of and interest and redemption premium, if any, on such bonds or other obligations on the maturity date or dates thereof or the specified redemption date or dates pursuant to such irrevocable instructions, as appropriate, and (2) which fund is sufficient, as verified by a nationally recognized independent certified public accountant or independent arbitrage consultant, to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this clause (ii) on the maturity date or dates thereof or on the redemption date or dates specified in the irrevocable instructions referred to above, as appropriate.

DTC shall mean The Depository Trust Company, New York, New York, a limited purpose trust company organized under the laws of the State of New York, in its capacity as Securities Depository for the Bonds.

Event of Default shall have the meaning ascribed thereto in Section 801.

Fiduciary or **Fiduciaries** shall mean the Trustee, the Bond Registrar, the Paying Agent or any or all of them, as may be appropriate.

Fiscal Year shall mean the 12-month period commencing at 0000 hours on July 1 of each year and ending at 2400 hours on the following June 30 or such other 12-month period as the Authority may adopt as its Fiscal Year.

Fitch shall mean Fitch Ratings, Inc. or, if such corporation is dissolved or liquidated or otherwise ceases to perform securities rating services, such other nationally recognized securities rating agency (other than Moody's and Standard & Poor's) as may be designated in writing by the Authority.

Fund shall mean the 2025 Series A Issue Fund established in Article V.

General Reserve Fund shall mean the fund so designated and established by the Senior Indenture.

Indenture or **Indenture of Trust** shall mean this Indenture of Trust as from time to time amended or supplemented by Supplemental Indentures of Trust in accordance with the terms hereof.

Information Services shall mean the Electronic Municipal Market Access System (referred to as "EMMA"), a facility of the Municipal Securities Rulemaking Board, at www.emma.msrb.org, and in accordance with then current guidelines of the Securities and Exchange Commission, Information Services shall also mean such other organizations providing information with respect to called bonds as the Authority may designate in writing to the Trustee.

Interest Payment Date shall mean, while any of the Bonds are Outstanding, January 1 and July 1 of each year, commencing July 1, 2025.

Investment Securities shall mean and include: (i) any of the securities that are at the time of purchase legal for investment of the Authority's funds under applicable law (including California Government Code Sections 53601 and 53635); (ii) investment agreements (including, but not limited to, guaranteed investment contracts, repurchase agreements, forward purchase agreements and reserve fund put agreements) with a domestic or foreign bank or corporation (other than a life or property casualty insurance company) the long-term debt of which, or, in the case of a monoline financial guaranty insurance company, claims paying ability of the guaranty for which, is rated at the time of execution of such investment agreement 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 or at such lower rating as permitted by the then current investment policies of the Authority; or (iii) other forms of investment for which confirmation is received from each Rating Agency then rating any of the Bonds that such investment will not adversely affect such Rating Agency's rating on such Bonds.

Issue Date shall mean the date of original issue of the Bonds pursuant to subsection 1 of Section 202 hereof.

Moody's shall mean Moody's Investors Service, Inc. or, if such corporation is dissolved or liquidated or otherwise ceases to perform securities rating services, such other nationally recognized securities rating agency (other than Standard & Poor's and Fitch) as may be designated in writing by the Authority.

Opinion of Bond Counsel shall mean an opinion signed by Bond Counsel.

Outstanding, when used with reference to Bonds, shall mean, as of any date, Bonds theretofore or thereupon being authenticated and delivered under this Indenture of Trust except for:

(i) Bonds cancelled by the Trustee on or prior to such date;

(ii) if applicable, Bonds (or portions of Bonds) for the payment or redemption of which moneys, equal to the principal amount or Redemption Price thereof, as the case may be, with interest, if any, to the date of maturity or redemption date, shall be held in trust under this Indenture of Trust and set aside for such payment or redemption (whether at or prior to the maturity or redemption date), provided that if such Bonds (or portions of Bonds) are to be redeemed, notice of such redemption shall have been given as in Article IV provided or provision satisfactory to the Trustee shall have been made for the giving of such notice;

(iii) Bonds in lieu of or in substitution for which other Bonds shall have been authenticated and delivered pursuant to Article III or Section 1106; and

(iv) Bonds deemed to have been paid as provided in subsection 2 of Section 1301.

Parity Swap shall mean any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement (including all confirmations, schedules, exhibits, attachments, appendices and other documentation attached to such agreement or forming a part thereof or incorporated therein) (a) that is entered into by the Authority and a Parity Swap Provider (and, if applicable, the Trustee), (b) that is permitted to be entered into by the Authority under the laws of the State of California applicable thereto at the time the Authority enters into such agreement, as evidenced by an opinion of counsel acceptable to the Authority, (c) as to which the documentation thereof provides that payments to be made by the Authority pursuant to such agreement (other than termination payments thereunder, which shall be payable on a basis subordinate and junior to the payments to be made on the Bonds and any other payments due on the Parity Swap) constitute obligations payable on a parity basis with the payments to be made on the Bonds as and to the extent provided in this Indenture of Trust and (d) designated in writing to the Trustee by an Authorized Authority Representative as a Parity Swap under this Indenture of Trust.

Parity Swap Provider shall mean, with respect to each Parity Swap, the entity (other than the Authority and, if applicable, the Trustee) that is a party thereto, and its permitted successors and assigns, whose public credit ratings, or whose obligations under a Parity Swap are guaranteed by a financial institution whose public credit ratings, are (at the time the applicable Parity Swap is entered into), unless otherwise approved by the Authority, in not lower than the second highest rating category (without regard to any gradations within any such category) by any two nationally-recognized credit rating agencies.

Paying Agent shall mean any bank or trust company organized under the laws of any state of the United States or any national banking association designated as paying agent for the Bonds, and its successor or successors hereafter appointed in the manner provided in this Indenture of Trust.

Person shall mean an individual, a corporation, a partnership, a limited liability company, an association, a joint stock company, a trust, any unincorporated organization, a governmental body or a political subdivision, a municipality, a municipal authority or any other group or organization of individuals.

Pledged Revenues shall mean all Available Revenues transferred to and deposited in the 2025 Series A Pledged Revenues Account pursuant to the Senior Indenture (including the Thirty-First Supplemental Indenture).

Principal Installment shall mean, as of any date of calculation, so long as any Bonds are Outstanding, (i) the principal amount of the Bonds due on a certain future date for which no Sinking Fund Installments have been established, or (ii) if applicable, the unsatisfied balance of any Sinking Fund Installments due on a certain future date for the Bonds plus the amount of the sinking fund redemption premiums, if any, that would be payable upon redemption of such Bonds on such future date in a principal amount equal to said unsatisfied balance of such Sinking Fund Installments, or (iii) if such future dates coincide as to different Bonds, the sum of such principal amount of Bonds and of such unsatisfied balance of Sinking Fund Installments due on such future date plus such applicable redemption premiums, if any.

Project Participants shall mean those entities that have executed Transmission Service Contracts, together in each case with their successors or assigns.

Rating Agency shall mean each of Moody's, Standard & Poor's and Fitch, if then rating the Bonds. Except as otherwise provided herein, if more than one Rating Agency maintains a credit rating with respect to the Bonds, then any action, approval or consent by or notice to a Rating Agency shall be effective only if such action, approval, consent or notice is given by or to each such Rating Agency.

Record Date shall mean, with respect to each Interest Payment Date for the Bonds, the 15th day of the calendar month immediately preceding such Interest Payment Date.

Redemption Price shall mean, if applicable, with respect to any Bond to be redeemed, the principal amount thereof plus the applicable premium, if any, payable upon redemption thereof pursuant to such Bond or this Indenture of Trust.

Refunded Bonds means all of the outstanding 2015 Series C Subordinate Bonds in the aggregate principal amount of $89,480,000, all as described in Exhibit B to the Thirty-First Supplemental Indenture.

Reserve Account Policy shall mean any surety bond, insurance policy, line of credit, letter of credit or similar instrument issued to the Trustee by a company 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 Bonds to which it relates (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.

Reserve Requirement shall mean an amount equal to $0.00.

Revenue Fund shall mean the Fund so designated and established by the Senior Indenture.

Revenues shall have the meaning ascribed thereto in the Senior Indenture.

Securities Depository shall mean DTC and its successors and assigns or if (i) the then Securities Depository resigns from its functions as depository of the Bonds or (ii) the Authority discontinues use of the then Securities Depository pursuant to Section 309, any other securities depository which agrees to follow the procedures required to be followed by a securities depository in connection with the Bonds and which is selected by the Authority.

Senior Bond shall mean any bond issued pursuant to the Senior Indenture at any time.

Senior Indenture shall mean the Indenture of Trust, dated as of May 1, 1983, as supplemented and amended from time to time, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee.

Sinking Fund Installment shall mean an amount, if any, so designated and established pursuant to Section 206.

Standard & Poor's shall mean S&P Global Ratings, a Standard & Poor's Financial Services LLC business, or, if such entity is dissolved or liquidated or otherwise ceases to perform securities rating services, such other nationally recognized securities rating agency (other than Moody's and Fitch) as may be designated in writing by the Authority.

Supplemental Indenture of Trust shall mean any indenture supplemental to or amendatory of this Indenture of Trust, executed and delivered by the Authority in accordance with Article X.

Thirty-First Supplemental Indenture shall mean the Thirty-First Supplemental Indenture of Trust, dated as of [_____] 1, 2025, as supplemented or amended from time to time, from the Authority to U.S. Bank Trust Company, National Association, as trustee, amending and supplementing the Senior Indenture as theretofore in effect.

Transmission Project shall have the meaning ascribed thereto in the Senior Indenture.

Transmission Project Agreements shall have the meaning ascribed thereto in the Senior Indenture.

Transmission Service Contracts shall mean the several Transmission Service Contracts between the Authority and the Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms.

Trustee shall mean the trustee under this Indenture of Trust, initially being U.S. Bank Trust Company, National Association, and its permitted successor or successors and any other corporation, association or other entity that may at any time be substituted in its place pursuant to this Indenture of Trust.

Vice President shall mean, with respect to the Authority, any Vice President, First Vice President or Second Vice President of the Authority.

2015 Series A and B Pledged Revenues Account shall mean the account so designated in the 2015 Series A and B Subordinated Indenture.

2015 Series A and B Subordinate Bonds shall mean the Authority's Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series A and 2015 Subordinate Series B (Federally Taxable), authorized by the 2015 Series A and B Subordinated Indenture.

2015 Series A and B Subordinated Indenture shall mean the Indenture of Trust relating to the 2015 Series A and Series B Subordinate Bonds, dated as of February 1, 2015, from the Authority to U.S. Bank Trust Company, National Association, as trustee, as supplemented and amended from time to time.

2015 Series C Pledged Revenues Account shall mean the account so designated in the 2015 Series C Subordinated Indenture.

2015 Series C Subordinate Bonds shall mean the Authority's Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C, authorized by the 2015 Series C Subordinated Indenture.

2015 Series C Subordinated Indenture shall mean the Indenture of Trust relating to the 2015 Series C Subordinate Bonds, dated as of March 1, 2015, from the Authority to U.S. Bank Trust Company, National Association, as trustee, as supplemented and amended from time to time.

2025 Series A Accrued Debt Service shall mean, as of any date of calculation, an amount equal to the amount of accrued Debt Service, calculating the accrued Debt Service as an amount equal to the sum of (i) interest on the Bonds accrued and unpaid and to accrue to the end of the then current calendar month, and (ii) Principal Installments on the Bonds due and unpaid and that portion of the Principal Installment on the Bonds that is to become due (if deemed to accrue in the manner set forth in the definition of Debt Service) by the end of such calendar month. For purposes of this definition, interest shall accrue with respect to each month of any Fiscal Year based on the total amount of interest payable on the January 1 included in such Fiscal Year and the next succeeding July 1, divided by twelve (12).

2025 Series A Charges Account shall mean the Account so designated and established in Section 502.

2025 Series A Costs of Issuance Account shall mean the Account so designated and established in Section 502.

2025 Series A Issue Fund shall mean the Fund so designated and established in Section 502.

2025 Series A Payment Account shall mean the Account so designated and established in Section 502.

2025 Series A Pledged Revenues Account shall mean the Account so designated and established in Section 502.

2025 Series A Remainder Account shall mean the Account so designated and established in Section 502.

2025 Series A Reserve Account shall mean the Account so designated and established in Section 502.

2025 Series A Subordinate Bonds Redemption Fund shall have the meaning ascribed thereto in the Thirty-First Supplemental Indenture.

Except where the context otherwise requires, words importing the singular shall include the plural and vice versa, and words importing persons shall include firms, associations, corporations, districts, agencies and bodies.

102. Authority for this Indenture of Trust; Findings. This Indenture of Trust is executed by the Authority pursuant to the provisions of the Act. The Authority is executing this Indenture of Trust, undertaking its obligations in respect of the acquisition of Authority Capacity and issuing the Bonds to finance or refinance the Cost of Acquisition of Authority Capacity for the benefit of the Project Participants, each of which is a member of the Authority.

103. Indenture of Trust to Constitute Contract. In consideration of the purchase and acceptance of any and all of the Bonds authorized to be issued hereunder by those who shall hold the same from time to time, (i) this Indenture of Trust shall be deemed to be and shall constitute a contract among the Authority, the Trustee, any Parity Swap Providers and the Owners from time to time of the Bonds and (ii) the pledge and assignment made in this Indenture of Trust and the covenants and agreements herein set forth to be performed on behalf of the Authority shall be for the equal benefit, protection and security of any Parity Swap Providers and the Owners of any and all of the Bonds, all of which Bonds, regardless of the time or times of their authentication and delivery or maturity, shall be of equal rank without preference, priority or distinction of any of the Bonds over any other thereof except as expressly provided in or permitted by this Indenture of Trust.

ARTICLE II

AUTHORIZATION AND ISSUANCE OF BONDS; APPLICATION OF PROCEEDS

201. Authorization of Bonds. This Indenture of Trust provides for the authorization, issuance, execution, authentication and delivery of Bonds of the Authority to be designated as "Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project)." The aggregate principal amount of the Bonds that may be executed, authenticated and delivered under this Indenture of Trust is limited to $[_____], except as provided in this Indenture of Trust or as may be limited by law.

202. General Provisions for Issuance of the Bonds

1. The Bonds shall be executed by the Authority for issuance under this Indenture of Trust and delivered to the Trustee and thereupon shall be authenticated by the Trustee and by it delivered to or upon the order of the Authority, but only upon the receipt by the Trustee of:

(a) An Opinion of Bond Counsel to the effect that (i) the Authority has the right and power to enter into this Indenture of Trust, and this Indenture of Trust has been duly authorized, executed and delivered by the Authority, and constitutes a valid and binding agreement of the Authority enforceable in accordance with its terms; (ii) this Indenture of Trust creates the valid pledge that it purports to create of the Pledged Revenues and funds held or set aside under this Indenture of Trust, subject only to the provisions of this Indenture of Trust permitting the application thereof for the purposes and on the terms and conditions set forth in this Indenture of Trust; and (iii) the Bonds are valid and binding obligations of the Authority as provided in this Indenture of Trust, and are entitled to the benefits of this Indenture of Trust and the applicable benefits of the Act, and such Bonds have been duly and validly authorized and issued in accordance with applicable law, including the Act, and in accordance with this Indenture of Trust; provided, that such opinion (A) may take exception for limitations on equitable remedies and limitations imposed by or resulting from bankruptcy, insolvency, moratorium, reorganization or other laws affecting creditors' rights generally and (B) need not express any opinion as to the availability of any specific remedy; and

(b) A written order as to the delivery of the Bonds, signed by an Authorized Authority Representative.

2. Except as otherwise provided herein, the Bonds shall be identical in all respects, except as to denominations, numbers, maturities, interest rates and letters. After the original issuance of the Bonds, no Bonds shall be issued except in lieu of or in substitution for other Bonds pursuant to Article III, Article IV or Section 1106.

203. **Date, Maturity and Interest**. The Bonds shall be dated the Issue Date. All the Bonds shall bear interest in accordance with Section 301. The Bonds shall be issued in Authorized Denominations and shall mature on the dates and in the principal amounts, and shall bear interest payable semiannually on January 1 and July 1, commencing on July 1, 2025, at the respective rates and yields per annum shown below:

July 1	Principal Amount	Interest Rate	Yield
2025	$	%	%
2026			
2027			

Interest on the Bonds shall be computed on the basis of a 360-day year consisting of twelve 30-day months.

204. **Place of Payment and Paying Agents**. Except as otherwise provided in Section 309, the principal and Redemption Price (if applicable) of the Bonds shall be payable upon surrender thereof at the principal corporate trust office of the Trustee (hereby designated a Paying Agent for the Bonds) or at the office of any other Paying Agent hereafter appointed by the Authority. Semiannual interest on the Bonds shall be payable (i) by check of the Trustee (except as otherwise provided in subsection 1 of Section 309) 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 on the Record Date or (ii) in immediately available funds by wire transfer on the Interest Payment Date to a designated account, if payable to any Owner of 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). Notwithstanding any provisions of this Indenture of Trust to the contrary, as provided in Section 1310, if the date for payment of the principal or Redemption Price (if applicable) of, premium, if any, or interest on the Bonds shall be a day which is not a Business Day, then the date for such payment shall be the next succeeding day which is a Business Day, and payment on such later date shall have the same force and effect as if made on the nominal date of payment, and no interest shall accrue for the period from and after such nominal date.

205. **No Optional Redemption**. Notwithstanding anything to the contrary in this Indenture of Trust, the Bonds shall not be subject to optional redemption prior to maturity.

206. **No Sinking Fund Installments**. Notwithstanding anything to the contrary in this Indenture of Trust, the Bonds shall not be subject to mandatory redemption prior to maturity.

207. **Receipt of Moneys; Application of Moneys Received by the Authority in Connection with the Issuance of the Bonds**. In accordance with the Thirty-First Supplemental Indenture, the moneys received by the Authority in connection with the issuance of the Bonds, together with certain other amounts to be deposited and transferred as set forth below, shall be applied simultaneously with the delivery of the Bonds as follows:

1. There shall be transferred to the Trustee (as trustee for the Refunded Bonds), for deposit in the 2025 Series A Subordinate Bonds Redemption Fund (a) proceeds of the Bonds (other than proceeds of the Bonds to be deposited in the 2025 Series A Costs of Issuance Account) in the amount of $[_____], and (b) $[____] of moneys transferred from the 2015 Series C Payment Account in the 2015 Series C Issue Fund referenced in the Twenty-Eighth Supplemental Indenture of Trust and provided for in the 2015 Series C Subordinated Indenture relating to accrued interest on the Refunded Bonds, all as provided in Section 201 of the Thirty-First Supplemental Indenture. Moneys so deposited shall be held uninvested as provided in the Thirty-First Supplemental Indenture. Such cash and other amounts transferred pursuant to the Thirty-First Supplemental Indenture, will provide moneys which will be sufficient to pay the interest becoming due on the Refunded Bonds on the date of redemption of the Refunded Bonds and the redemption price of the Refunded Bonds on the redemption date specified in the Thirty-First Supplemental Indenture.

2. There shall be transferred to the Trustee for deposit in the 2025 Series A Costs of Issuance Account in the 2025 Series A Issue Fund the amount of $[____], representing the balance of the proceeds of the Bonds, to be applied by the Trustee at the direction of the Authority to the payment of Costs of Issuance of the Bonds as provided in Section 509.

ARTICLE III

GENERAL TERMS AND PROVISIONS OF BONDS

301. Medium of Payment; Form and Date; Letters and Numbers. The Bonds shall be payable, with respect to interest, principal and Redemption Price (if applicable), in any currency of the United States of America that at the time of payment is legal tender for the payment of public and private debts. The Bonds shall be issued in the form of fully registered Bonds without coupons, in Authorized Denominations. The Bonds shall be issued in substantially the form set forth in Exhibit A hereto. Interest shall be paid to the Persons in whose name the Bonds are registered on the Record Date. Interest on the Bonds shall accrue from the most recent Interest Payment Date to which interest has been paid or duly provided for, unless the date thereof is an Interest Payment Date on which interest has been paid, in which case from the date thereof, or unless the date thereof is on or prior to June 15, 2025, in which case from the Issue Date, or, unless the date thereof is between a Record Date and the next succeeding Interest Payment Date, in which case interest shall be payable from such Interest Payment Date. The Bonds shall be numbered as the Trustee shall determine.

302. Legends. The Bonds may contain or have endorsed thereon such provisions, specifications and descriptive words not inconsistent with the provisions of this Indenture of Trust as may be necessary or desirable to comply with custom, the rules of any securities exchange or commission or brokerage board, or otherwise, as may be determined by the Authority prior to the authentication and delivery thereof.

303. Execution and Authentication.

1. The Bonds shall be executed in the name of the Authority by the manual or facsimile signature of the President or Vice President of the Authority and its seal (or a facsimile thereof) shall be impressed, imprinted, engraved or otherwise reproduced thereon and

attested by the facsimile or manual signature of its Secretary or an Assistant Secretary, or in such other manner as may be required or permitted by law. In case any one or more of the officers who shall have executed or attested to the seal on any of the Bonds shall cease to be such officer before the Bonds so executed or attested shall have been authenticated and delivered by the Trustee such Bonds may, nevertheless, be authenticated and delivered as herein provided, and may be issued as if the persons who executed or attested to the seal on any of the Bonds had not ceased to hold such offices. Any Bond may be executed and sealed on behalf of the Authority by such persons as at the time of the execution of such Bonds shall be duly authorized or hold the proper office in the Authority, although at the date borne by such Bonds such persons may not have been so authorized or have held such office.

2. The Bonds shall bear thereon a certificate of authentication, in substantially the form set forth in Exhibit A hereto, executed manually by the Trustee. Only such Bonds as shall bear thereon such certificate of authentication shall be entitled to any right or benefit under this Indenture of Trust, and no Bond shall be valid or become obligatory for any purpose until such certificate of authentication shall have been duly executed by the Trustee. Such certificate of the Trustee upon any Bond executed on behalf of the Authority shall be conclusive evidence that the Bond so authenticated has been duly authenticated and delivered under this Indenture of Trust and that the Owner thereof is entitled to the benefits of this Indenture of Trust.

304. Exchange, Registration of Transfer and Registry.

1. Subject to Section 309, the transfer of any 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 Bond Registrar, by the Owner thereof in person or by his or her attorney duly authorized in writing, upon surrender of such 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 as provided in Section 305. Upon the registration of transfer of any Bond, the Authority shall issue in the name of the transferee a new registered Bond or Bonds of like tenor, in the same aggregate principal amount, maturity and interest rate, and in the same denomination, or in different Authorized Denominations equal in the aggregate to the principal amount of the surrendered Bond. The Bond Registrar may, with the concurrence of the Authority, designate an additional office where transfer of Bonds may be registered by the Bond Registrar as provided in this subsection 1 of this Section 304.

2. Subject to Section 309, Bonds may, at the option of the Owner upon surrender thereof at the principal corporate trust office of the Bond Registrar and upon payment by such Owner of any charges which the Authority or the Trustee may impose as provided in Section 305, be exchanged for an equal aggregate principal amount of Bonds of the same tenor, maturity and interest rate in such other Authorized Denomination or Denominations as shall be requested by such Owner.

3. In the case of any Bond properly surrendered for partial redemption, if applicable, the Trustee shall authenticate and deliver a new Bond in exchange therefor, such new Bond to be of the same tenor and maturity and in a denomination equal to the unredeemed principal amount of the surrendered Bond; provided that, at its option, the Trustee may certify

the amount and date of partial redemption upon the partial redemption certificate, if any, printed on the surrendered Bond and return such surrendered Bond to the Owner in lieu of an exchange.

4. The Authority and each Fiduciary may deem and treat the person in whose name any Bond is registered upon the books of the Authority as the absolute owner of such Bond, whether such Bond shall be overdue or not, for the purpose of receiving payment of, or on account of, the principal or Redemption Price (if applicable) of and interest on such Bond and for all other purposes, and all such payments so made to any such Owner or upon his or her order shall be valid and effective to satisfy and discharge the liability upon such Bond to the extent of the sum or sums so paid, and neither the Authority nor any Fiduciary shall be affected by any notice to the contrary. The Authority, subject to Section 1311, agrees, to the extent permitted by law, to indemnify each Fiduciary and hold each harmless from and against any and all loss, cost, charge, expense, judgment or liability incurred by it, acting in good faith and without negligence under this Indenture of Trust, in so treating such Owner.

305. Regulations With Respect to Registration of Exchanges and Transfers. Subject to Section 309, in all cases in which the transfer of any Bond is registered or any Bonds are exchanged, the Authority shall execute and the Trustee shall authenticate and deliver new Bonds in accordance with the provisions of this Indenture of Trust. All Bonds surrendered in any such exchange or registration of transfer shall forthwith be delivered to and cancelled by the Trustee. For every such exchange or registration of transfer of Bonds, the Authority or the Trustee may impose a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect thereto. At no time shall the Bond Registrar be required to register the transfer of, or exchange, any Bonds called for redemption (if applicable) or any Bonds during the period of fifteen (15) days next preceding any selection of Bonds to be redeemed (if applicable).

306. Bonds Mutilated, Destroyed, Stolen or Lost. Subject to Section 309, if any Bond becomes mutilated or is lost, stolen or destroyed, the Authority may execute and the Trustee shall authenticate and deliver a new Bond of like tenor, date of issue, maturity date, principal amount and interest rate per annum as the Bond so mutilated, lost, stolen or destroyed, provided that (i) in the case of such mutilated Bond, such Bond is first surrendered to the Trustee, (ii) in the case of any such lost, stolen or destroyed Bond, there is first furnished evidence of such loss, theft or destruction satisfactory to the Authority and the Trustee together with indemnity satisfactory to the Authority and the Trustee, (iii) all other reasonable requirements of the Authority and the Trustee are complied with, and (iv) expenses in connection with such transaction are paid by the Owner. Any such mutilated Bond surrendered for exchange shall be cancelled. Any such new Bonds issued pursuant to this Section 306 in substitution for Bonds alleged to be destroyed, stolen or lost shall constitute original additional contractual obligations on the part of the Authority, whether or not the Bonds so alleged to be destroyed, stolen or lost be at any time enforceable by anyone, and shall be equally secured by and entitled to equal and proportionate benefits with all other Bonds issued under this Indenture of Trust, in any moneys or securities held by the Authority or any Fiduciary for the benefit of the Owners.

307. Temporary Bonds.

1. Until the definitive Bonds are prepared, the Authority may execute, in the same manner as is provided in Section 303, and upon the request of the Authority, the Trustee shall authenticate and deliver, in lieu of definitive Bonds, but subject to the same provisions, limitations and conditions as definitive Bonds except as to the denominations thereof and as to exchangeability of Bonds, one or more temporary Bonds in Authorized Denominations, of substantially the tenor of the definitive Bonds in lieu of which such temporary Bond or Bonds are issued, with such omissions, insertions and variations as may be appropriate to temporary Bonds. The installments of interest on such temporary Bonds shall be payable by check of the Trustee mailed by first-class mail, postage prepaid, to the Owner thereof in the same manner as is set forth in this Indenture of Trust authorizing the Bonds in lieu of which such temporary Bonds are issued. Subject to Section 1311, the Authority at its own expense shall prepare and execute and, upon the surrender of such temporary Bonds for exchange and the cancellation of such surrendered temporary Bonds, the Trustee shall authenticate and, without charge to the Owner thereof, deliver in exchange therefor, definitive Bonds of the same aggregate principal amount, maturity and interest rate as the temporary Bonds surrendered. Until so exchanged, the temporary Bonds shall in all respects be entitled to the same benefits and security as definitive Bonds authenticated and issued pursuant to this Indenture of Trust.

2. If the Authority shall authorize the issuance of temporary Bonds in more than one denomination, the Owner of any temporary Bond or Bonds may, at his or her option, surrender the same to the Trustee in exchange for another temporary Bond or Bonds of like aggregate principal amount, maturity and interest rate of any other Authorized Denomination or Denominations, and thereupon the Authority shall execute and the Trustee shall authenticate and, in exchange for the temporary Bond or Bonds so surrendered and upon payment of the taxes, fees and charges provided for in Section 305, shall deliver a temporary Bond or Bonds of like aggregate principal amount, maturity and interest rate in such other Authorized Denomination or Denominations as shall be requested by such Owner.

3. All temporary Bonds surrendered in exchange either for another temporary Bond or Bonds or for a definitive Bond or Bonds shall be forthwith cancelled by the Trustee.

308. Cancellation and Destruction of Bonds. All Bonds paid or redeemed, either at or before maturity, shall be delivered to the Trustee when such payment or redemption is made, and such Bonds, together with all Bonds purchased by the Trustee, shall thereupon be promptly cancelled. Whenever Bonds are cancelled by the Trustee pursuant to the provisions of this Indenture of Trust, the Bonds so cancelled shall be destroyed by the Trustee, who shall execute a certificate of destruction in duplicate by the signature of one of its authorized officers describing the Bonds so destroyed, and one executed certificate shall be filed with the Authority and the other executed certificate shall be retained by the Trustee.

309. Book-Entry Format.

1. Except as provided in this Section 309, the ownership of one fully registered Bond for each maturity of the Bonds shall be registered in the name of the Securities Depository or its nominee and ownership thereof shall be maintained in book-entry form by the

Securities Depository for the account of the Agent Members. Initially, each Bond shall be registered in the name of Cede & Co. ("Cede"), as nominee of DTC. Payments of interest on and principal and Redemption Price (if applicable) of the Bonds shall be made to the account of DTC on each payment date therefor at the address indicated for DTC in the registration books of the Authority kept by the Trustee. DTC has represented to the Authority that it will maintain a book-entry system for recording ownership interests of its Agent Members and the ownership interests of a purchaser of a beneficial interest in the Bonds (a "Beneficial Owner") will be recorded through book entries on the records of the Agent Members. Except as provided in this Section 309, the Bonds may be transferred, in whole but not in part, only to the Securities Depository or a nominee of the Securities Depository, or to a successor Securities Depository selected by the Authority or to a nominee of such successor Securities Depository. Each global Bond shall bear a legend substantially to the following effect: "UNLESS THIS BOND IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY, A NEW YORK CORPORATION ("DTC"), TO THE AUTHORITY OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE, OR PAYMENT, AND ANY BOND ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR IN SUCH OTHER NAME AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR TO SUCH OTHER ENTITY AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE, OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN."

2. The Bonds shall be initially issued in the form of a separate single fully registered Bond in the amount of each separate stated maturity (unless bonds of the same stated maturity shall have different interest rates, in which case there shall be a separate fully registered Bond for each such interest rate of such maturity), subject to the first sentence of subsection 1 of this Section 309. With respect to said Bonds, the Authority and the Fiduciaries shall have no responsibility or obligation to any Agent Member or to any Beneficial Owner of such Bonds. Without limiting the immediately preceding sentence, the Authority and the Fiduciaries shall have no responsibility or obligation with respect to (i) the accuracy of the records of the Securities Depository or any Agent Member with respect to any beneficial ownership interest in the Bonds, (ii) the delivery to any Agent Member, Beneficial Owner or other Person, other than the Securities Depository, of any notice with respect to the Bonds, including any notice of redemption, (iii) the payment to any Agent Member, Beneficial Owner or other Person, other than the Securities Depository, of any amount with respect to the principal or Redemption Price (if applicable) of, or interest on, the Bonds, (iv) any consent given or other action taken by the Securities Depository as Owner of the Bonds, or (v) the selection by DTC, Cede or any Agent Member of any Beneficial Owners to receive payment if Bonds are redeemed in part. So long as certificates for the Bonds are issued pursuant to this Section 309, the Authority and the Fiduciaries may treat the Securities Depository as, and deem the Securities Depository to be, the absolute Owner of each Bond for all purposes whatsoever including (but not limited to) (x) payment of the principal or Redemption Price of, and interest on, each such Bond, (y) giving notices of purchase or redemption and other matters with respect to such Bonds, and (z) registering transfers with respect to such Bonds. The Trustee shall pay the principal or Redemption Price of, and interest on, all Bonds only to or upon the order of the Securities Depository, and all such payments shall be valid and effective to fully satisfy and discharge the

Authority's obligations with respect to such principal or Redemption Price, and interest, to the extent of the sum or sums so paid. Except as provided in this Section 309, no Person other than the Securities Depository shall receive a Bond evidencing the obligation of the Authority to make payments of principal or Redemption Price of, and interest on, the Bonds pursuant to this Indenture of Trust.

3. (a) The Securities Depository may determine to discontinue providing its services with respect to the Bonds at any time by giving reasonable written notice to the Authority and the Fiduciaries and discharging its responsibilities with respect thereto under applicable law.

(b) The Authority, in its sole discretion and without the consent of any other Person, may terminate, upon giving of notice to the Fiduciaries, the services of the Securities Depository with respect to the Bonds if the Authority determines that the continuation of the system of book-entry transfers through the Securities Depository (or a successor securities depository) is not in the best interests of the Beneficial Owners of the Bonds or is burdensome to the Authority, and shall terminate the services of the Securities Depository with respect to the Bonds upon receipt by the Authority and the Fiduciaries of written notice from the Securities Depository to the effect that the Securities Depository has received written notice from Agent Members having interests, as shown in the records of the Securities Depository, in an aggregate principal amount of not less than fifty percent (50%) of the aggregate principal amount of the then Outstanding Bonds to the effect, that: (i) the Securities Depository is unable to discharge its responsibilities with respect to such Bonds; or (ii) a continuation of the requirement that all of the Outstanding Bonds be registered in the registration books kept by the Trustee in the name of the Securities Depository or its nominee is not in the best interest of the Beneficial Owners of such Bonds.

4. Upon the termination of the services of the Securities Depository with respect to the Bonds pursuant to clause (ii) of subsection 3(b) of this Section 309, or upon the discontinuance or termination of the services of the Securities Depository with respect to the Bonds pursuant to subsection 3(a) or clause (i) of subsection 3(b) of this Section 309 after which no substitute securities depository willing to undertake the functions of the Securities Depository hereunder can be found or which, in the opinion of the Authority, is willing and able to undertake such functions upon reasonable and customary terms, the Bonds shall no longer be restricted to being registered in the registration books kept by the Trustee in the name of the Securities Depository. In such event, the Authority shall issue and the Trustee shall register the transfer of and exchange Bond certificates, as requested by the Securities Depository or Agent Members, of like principal amount and maturity, in Authorized Denominations to the Beneficial Owners in replacement of such Beneficial Owners' beneficial interests in the Bonds. The Trustee shall deliver such certificates representing such Bonds to the persons in whose names such Bonds are so registered as soon as practicable.

5. Except as otherwise provided herein, so long as any Bond is registered in the name of the Securities Depository or its nominee all payments with respect to the principal or Redemption Price (if applicable) of, and interest on, such Bond and all notices to Owners with respect to such Bond shall be made and given, respectively, to the Securities Depository as provided in the "blanket letter of representations" from the Authority to the Securities Depository (as such letter shall be amended from time to time).

6. In connection with any notice or other communication to be provided to Owners pursuant to this Indenture of Trust by the Trustee with respect to any consent or other action to be taken by Owners so long as any Bond is registered in the name of the Securities Depository or its nominee, the Authority or the Trustee shall establish a record date for such consent or other action and give the Securities Depository notice of such record date not less than fifteen (15) calendar days in advance of such record date to the extent possible (or such shorter time period as may be acceptable to the Securities Depository).

7. Notwithstanding any provision herein to the contrary, the Authority and the Trustee may agree to allow the Securities Depository or its nominee to make a notation on any Bond redeemed in part to reflect, for informational purposes only, the principal amount and date of any such redemption.

ARTICLE IV

REDEMPTION OF BONDS

401. Redemption and Redemption Price. Bonds subject to redemption prior to maturity pursuant to this Indenture of Trust (if any) shall be redeemable, upon notice as provided in this Article IV, at such times, in whole or in part, at such Redemption Price and upon such terms in addition to the terms contained in this Article IV as may be specified in this Indenture of Trust.

402. Redemption at the Direction of the Authority. Whenever by the terms of this Indenture of Trust, Bonds are to be redeemed at the direction of the Authority (if applicable), the Authority shall give written notice to the Trustee of its direction so to redeem, of the redemption date, and of the principal amounts of the Bonds of each maturity (or portion thereof) to be redeemed (which maturities and principal amounts (or portion thereof) thereof to be redeemed (including in the case of term Bonds redeemed in part at the direction of the Authority, the Sinking Fund Installments to which such portion redeemed shall be allocated) shall be determined by the Authority in its sole discretion, subject to any limitations with respect thereto contained in this Indenture of Trust). Such notice shall be given at least forty-five (45) days prior to the redemption date or such shorter period as shall be acceptable to the Trustee in the sole discretion of the Trustee. In the event notice of redemption shall have been given as provided in Section 404, there shall be paid by the redemption date to the Trustee or Paying Agent an amount in cash that, in addition to other moneys, if any, available therefor held by such Paying Agent, will be sufficient to redeem on the redemption date at the Redemption Price thereof, plus interest accrued and unpaid to the redemption date, all of the Bonds to be redeemed (unless the notice of redemption shall expressly provide that such redemption is conditioned on the receipt of funds therefor in accordance with Section 405 hereof).

403. Redemption Otherwise Than at the Authority's Election or Direction. Whenever the Trustee is required pursuant to Section 206 to redeem the Bonds otherwise than at the election or direction of the Authority, the Trustee shall give the notice of redemption to the extent required by this Article IV and pay out of moneys available therefor the Redemption Price thereof, plus interest accrued and unpaid to the redemption date, to the appropriate Paying Agents in accordance with the terms of this Article IV.

404. Selection of Bonds to be Redeemed. In the event less than all of the Bonds shall be called for redemption (if applicable), the Authority shall select the maturity or maturities to be redeemed. If less than all of the Bonds of like maturity shall be called for redemption (if applicable), the particular Bonds or portions of Bonds to be redeemed shall be selected by the Trustee by lot or in such other manner as the Trustee in its discretion may deem appropriate; provided, however, that the portion of any Bond to be redeemed (if applicable) shall be in the principal amount of an Authorized Denomination and, in selecting portions of such Bonds for redemption, the Trustee shall treat each such Bond as representing that number of Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Bond to be redeemed in part by $5,000.

405. Notice of Redemption.

1. When the Trustee shall receive notice from the Authority of its direction to redeem Bonds pursuant to Section 402 (if applicable), and when redemption of Bonds pursuant to Section 206 is authorized or required pursuant to Section 403 (if applicable), if the Trustee shall give notice, in the name of the Authority, of the redemption of such Bonds, not less than thirty (30) nor more than sixty (60) days prior to the redemption date (i) by first-class mail, postage prepaid, to the respective Owners of any Bonds or portions of Bonds designated for redemption, at their addresses appearing upon the registry books of the Trustee, and (ii) by certified, registered or overnight mail or by telecopy, email transmission, or other electronic means of communication to the Information Services and the Securities Depository. Failure to give notice to any one or more of the Information Services or Securities Depository, or any defect in such notice, shall not affect the validity of the proceedings for the redemption of Bonds. Failure by the Trustee to mail notice of redemption pursuant to this Section 405 to any one or more of the Owners of any of the Bonds designated for redemption or any defect in any such notice shall not affect the validity of the proceedings for the redemption of Bonds. Each notice of redemption shall state the date of such notice, the redemption date, the Redemption Price, the place or places of redemption (including the name and appropriate address or addresses of the Trustee), the CUSIP number, if any, of each maturity then being called for redemption and, if less than all of such maturity, the distinctive letters, numbers or other distinguishing marks of such maturity to be redeemed in part, and, in the case of Bonds to be redeemed in part only, such notice shall also specify the respective portions of the principal amount thereof to be redeemed. Such notice shall further state that on such date, if sufficient moneys are then available for such redemption, there shall become due and payable, upon each Bond to be redeemed, the Redemption Price thereof or the Redemption Price of the specified portions of the principal thereof in the case of Bonds to be redeemed in part only, together with interest accrued to the redemption date, and that from and after such date, interest thereon shall cease to accrue, and shall require that such Bonds be surrendered at the address or addresses of the Trustee specified in the redemption notice.

2. If by the date of mailing of notice of any optional redemption the Authority shall not have deposited with the Trustee moneys sufficient to redeem all the Bonds called for redemption, then such notice shall state that it is subject to the availability of funds for such purpose not later than the opening of business on the redemption date and shall be of no effect unless funds sufficient for such purpose are available.

406. Payment of Redeemed Bonds. Notice having been given in the manner provided in Section 405, and moneys sufficient therefor having been deposited by the Authority with the Trustee, the 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 Bonds, or portions thereof, shall be paid at the Redemption Price, plus interest accrued and unpaid to the redemption date. If there shall be selected for redemption less than all of a Bond, the Authority shall execute and the Trustee shall authenticate and deliver, upon the surrender of such Bond, without charge to the Owner thereof, for the unredeemed balance of the principal amount of the Bond so surrendered, a Bond or Bonds of like tenor and maturity in Authorized Denominations. Any new Bond or Bonds issued pursuant to this paragraph shall be executed by the Authority and authenticated by the Trustee and shall be in any Authorized Denominations in an aggregate unpaid principal amount equal to the unredeemed portion of the Bond surrendered. If, on the redemption date, moneys for the redemption of all the Bonds or portions thereof to be redeemed, together with interest accrued and unpaid to the redemption date, shall be held by the Trustee or Paying Agent so as to be available therefor on said date and if notice of redemption shall have been mailed as aforesaid, then, from and after the redemption date interest on the Bonds or portions thereof so called for redemption shall cease to accrue and become payable. If said moneys shall not be so available on the redemption date, such Bonds or portions thereof shall continue to bear interest, if any, until paid at the same rate as they would have borne had they not been called for redemption and such failure to pay the Redemption Price thereof shall not constitute an Event of Default under Section 801 of this Indenture of Trust.

ARTICLE V

ESTABLISHMENT OF FUND AND APPLICATION THEREOF

501. Bonds Limited Obligations.

1. The Authority does hereby pledge and assign to the Trustee, for the benefit of the Owners and any Parity Swap Providers, (a) the Pledged Revenues and (b) the 2025 Series A Issue Fund and all Accounts therein established by this Indenture of Trust; subject only to the provisions of this Indenture of Trust and the Thirty-First Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in this Indenture of Trust and the Thirty-First Supplemental Indenture, respectively, 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 this Indenture of Trust, all in accordance with the provisions of the Bonds, this Indenture of Trust, the Thirty-First Supplemental Indenture and any Parity Swaps. The Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or Redemption Price (if applicable) thereof, and interest thereon, in accordance with their terms and the provisions of this Indenture of Trust and the Thirty-First Supplemental Indenture solely by the moneys, Fund and Accounts set forth in this Section 501. The pledge made hereby is valid and binding upon delivery of the Bonds, and the Pledged Revenues and the 2025 Series A Issue Fund shall immediately be subject to the lien of such pledge without any physical delivery

thereof or any further act, and the lien of this pledge shall be valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the Authority irrespective of whether such parties have notice thereof. The Bonds and any Parity Swaps shall not be deemed to be Bonds as defined in the Senior Indenture.

2. The Bonds shall be payable, as to principal or Redemption Price (if applicable) thereof, and interest thereon, and any Parity Swaps shall be payable, solely as provided in this Indenture of Trust and the Thirty-First Supplemental Indenture and neither the State of California nor any public agency (other than the Authority) nor any member of the Authority nor any Project Participant shall be obligated to pay the principal or Redemption Price thereof or interest thereon or the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. 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 any Project Participant is pledged to the payment of the principal or Redemption Price of or interest on the Bonds or the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. The Bonds and any Parity Swaps 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, nor shall they constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit.

502. Establishment of 2025 Series A Issue Fund. The 2025 Series A Issue Fund is hereby established and shall be held by the Trustee. The following Accounts are hereby established within the 2025 Series A Issue Fund:

(i) 2025 Series A Pledged Revenues Account,

(ii) 2025 Series A Payment Account,

(iii) 2025 Series A Reserve Account,

(iv) 2025 Series A Charges Account,

(v) 2025 Series A Remainder Account, and

(vi) 2025 Series A Costs of Issuance Account.

The Trustee may, with the prior written consent of the Authority, establish additional accounts or subaccounts within the Fund or any of the Accounts, respectively, if the Trustee determines that such additional accounts or subaccounts would be advantageous or desirable.

503. Deposit of Pledged Revenues. All Pledged Revenues shall be promptly deposited upon receipt thereof to the credit of the 2025 Series A Pledged Revenues Account.

504. Payments Into Certain Accounts. As soon as practicable in each month after the deposit of Pledged Revenues into the 2025 Series A Pledged Revenues Account, but in any case no later than 12:00 noon, New York City time, on the last Business Day of such month, the Trustee shall transfer from the 2025 Series A Pledged Revenues Account to the following Accounts in the following order of priority the amounts set forth below:

(i) To the 2025 Series A Payment Account, the amount, if any, required so that the balance in said Account shall equal the sum of (A) the 2025 Series A Accrued Debt Service as of the last day of the then current month, and (B) all amounts due and payable by the Authority under any Parity Swaps during such month (or the entire amount transferred by the Trustee from the 2025 Series A Pledged Revenues Account if less than the required amount);

(ii) To the 2025 Series A Reserve Account, upon the occurrence of any deficiency therein (if applicable), (a) if the 2025 Series A Reserve Account is at that time funded by a Reserve Account Policy the provider of which has not failed to make payments thereunder, the amount of each unreplenished prior withdrawal from the 2025 Series A Reserve Account so that the provider of the Reserve Account Policy has been repaid for any draw made under such Policy for such Account or (b) if the 2025 Series A Reserve Account is not at that time funded by a Reserve Account Policy or, if funded by a Reserve Account Policy, the provider of such Reserve Account Policy has failed to make payment thereunder, the amount, if any, required for such Account to equal the Reserve Requirement as of the last day of the then current month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposit in clause (i) above if less than the required amount);

(iii) To the 2025 Series A Charges Account, the amount, if any, required so that the balance in such Account equals the sum of all amounts accrued or due and payable by the Authority as fees and charges to the Trustee or Paying Agent during such month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposits in clauses (i) and (ii) above if less than the required amount); and

(iv) To the 2025 Series A Remainder Account, the remaining balance, if any, of moneys in the 2025 Series A Pledged Revenues Account after making the above deposits.

505. 2025 Series A Payment Account.

1. The Trustee shall pay out of the 2025 Series A Payment Account, subject to subsections 2 and 3 of this Section 505, without preference or priority of one transfer over the others (i) to the Paying Agent (a) on or before each Interest Payment Date the amount required for the interest payable on the Bonds on such date, (b) on or before each Principal Installment due date, the amount required for the Principal Installment payable on such due date, and (c) on or before any redemption date for the Bonds, the amount required for the payment of principal, premium, if any, and interest on the Bonds then to be redeemed, and (ii) to any Parity Swap Providers, any amounts due and payable by the Authority under the Parity Swaps during such month. Amounts so paid to the Paying Agent with respect to the Bonds shall be applied by the Paying Agent on and after the due dates thereof. The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable pursuant to clause (ii) of this subsection 1 of this Section 505. Notwithstanding anything to the contrary in this Indenture of Trust, payments due to any Parity Swap Providers during a given month shall not be paid earlier in such month than the payment of any interest or Principal Installment due during such month.

2. All amounts held at any time in the 2025 Series A Payment Account shall be held until applied on a parity basis for the ratable security and payment of (i) 2025 Series A Accrued Debt Service and (ii) amounts due and payable by the Authority under any Parity Swaps, at any time in proportion to the amounts accrued or due and payable, as applicable.

3. In the event of the refunding of all or a portion of the Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the 2025 Series A Payment Account amounts accumulated therein with respect to Debt Service on the Bonds being refunded and, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, of and interest on the maturity or maturities of Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the maturity or maturities of Bonds being refunded shall be deemed to have been paid pursuant to subsection 2 of Section 1301, and (b) the amount (if any) remaining in the 2025 Series A Payment Account after such withdrawal shall not be less than the requirement of such Account pursuant to paragraph (i) of Section 504.

506. 2025 Series A Reserve Account.

1. Initially, the 2025 Series A Reserve Account shall not be funded. Thereafter, the 2025 Series A Reserve Account may be funded, in the sole discretion of the Board of Directors, at such level as determined by the Board of Directors. In the event that the 2025 Series A Reserve Account shall at any time be funded, the Authority may, at its option as provided in Section 601, provide for the funding of the 2025 Series A Reserve Account (in whole or in part) by the deposit thereto of a Reserve Account Policy.

2. If at any time the amount in the 2025 Series A Payment Account shall be less than the amount required to be in such Account pursuant to paragraph (i) of Section 504, the Trustee shall transfer amounts (if any) from the 2025 Series A Reserve Account to the 2025 Series A Payment Account (or, if applicable, the Trustee shall draw on the Reserve Account Policy (if any) and deposit the proceeds thereof in the 2025 Series A Payment Account) to the extent necessary to make good the deficiency.

3. Whenever the moneys on deposit in the 2025 Series A Reserve Account shall exceed the Reserve Requirement, if any, such excess (to the extent not required to be transferred to the trustee for the Senior Bonds pursuant to Section 601) shall be transferred to the 2025 Series A Pledged Revenues Account.

4. In the event of the refunding of all or any portion of the Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, transfer from the 2025 Series A Reserve Account any amounts accumulated therein and, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, and interest on the maturity or maturities of Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the maturity or maturities of Bonds being refunded shall be deemed to have been paid pursuant to subsection 2 of Section 1301, and (b) the amount remaining in the 2025 Series A Reserve Account after such withdrawal shall not be less than the requirement of such Account pursuant to paragraph (ii) of Section 504.

5. [Reserved.]

6. If a Reserve Account Policy shall be in full force and effect, any deposits required to be made with respect to the 2025 Series A Reserve Account pursuant to Section 504 shall include any amounts due to the provider of such Reserve Account Policy resulting from a draw on such Reserve Account Policy (which amounts shall constitute a "deficiency" or "withdrawal" from the 2025 Series A Reserve Account within the meaning of Section 504). Any such amounts shall be paid to the provider of any Reserve Account Policy as provided in such Reserve Account Policy or any related agreement.

507. 2025 Series A Charges Account.

1. The Trustee shall transfer from the 2025 Series A Charges Account moneys in the following amounts and in the following order of priority: (i) to the 2025 Series A Payment Account and the 2025 Series A Reserve Account the amount necessary (or all the moneys in the 2025 Series A Charges Account if less than the amount necessary) to make up any deficiencies in payments to said 2025 Series A Payment Account and 2025 Series A Reserve Account required by paragraphs (i) and (ii) of Section 504, and (ii) in the event of any transfer of moneys from the 2025 Series A Reserve Account to the 2025 Series A Payment Account, to the 2025 Series A Reserve Account the amount of the deficiency in such Account resulting from such transfer.

2. The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable pursuant to this Section 507 and, subject to subsection 1 of this Section 507, the Trustee shall pay out of the 2025 Series A Charges Account to the Trustee and the Paying Agent, the amounts due and payable by the Authority as fees and charges to each of them for their charges and costs during such month.

508. 2025 Series A Remainder Account.

1. The Trustee shall transfer from the 2025 Series A Remainder Account moneys in the following amounts and in the following order of priority: (i) to the 2025 Series A Payment Account and the 2025 Series A Reserve Account the amount necessary (or all the moneys in the 2025 Series A Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2025 Series A Payment Account and 2025 Series A Reserve Account required by paragraphs (i) and (ii) of Section 504; (ii) in the event of any transfer of moneys from the 2025 Series A Reserve Account to the 2025 Series A Payment Account, to the 2025 Series A Reserve Account the amount of the deficiency in such Account resulting from such transfer; and (iii) to the 2025 Series A Charges Account the amount necessary (or all the moneys in the 2025 Series A Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2025 Series A Charges Account required by paragraph (iii) of Section 504.

2. Amounts in the 2025 Series A Remainder Account not required to meet a deficiency as required in subsection 1 of Section 508 and not required to be transferred to the trustee for the Senior Bonds pursuant to Section 601 shall, upon a determination of the Authority evidenced by a certificate of an Authorized Authority Representative delivered to the Trustee

and after consultation with Bond Counsel, be applied to or set aside for any lawful purpose of the Authority related to the Transmission Project or the Authority Capacity.

509. 2025 Series A Costs of Issuance Account. Amounts deposited in the 2025 Series A Costs of Issuance Account shall be expended from time to time to pay Costs of Issuance upon receipt by the Trustee of a requisition or other written directions signed by an Authorized Authority Representative. If any amount shall remain in the 2025 Series A Costs of Issuance Account when all Costs of Issuance have been paid, as stated in a certificate of an Authorized Authority Representative, such amount shall be transferred to the 2025 Series A Remainder Account or if no such certificate is received, then one hundred eighty (180) days after the Issue Date of the Bonds the Trustee shall make such transfer and the 2025 Series A Costs of Issuance Account shall be closed.

ARTICLE VI

INVESTMENT OF FUNDS

601. Investment of Certain Funds.

1. Subject to Section 504, moneys held in the 2025 Series A Issue Fund or any Account therein shall be invested and reinvested by the Trustee to the fullest extent practicable in Investment Securities that mature or are available not later than such times as shall be necessary to provide moneys when needed for payments to be made from such Fund or Accounts; provided, however, that amounts in the 2025 Series A Remainder Account shall be invested and reinvested by the Trustee in Investment Securities that mature or are available within five years from the date of such investment, and in any case, the Investment Securities in such Fund or Accounts shall mature or be available no later than such times as shall be necessary to provide moneys when needed to provide payments from such Accounts. The 2025 Series A Reserve Account, if funded, may be funded (in whole or in part) with a Reserve Account Policy. The Trustee shall make all such investments of moneys held by it in accordance with written directions of an Authorized Authority Representative and if no such directions are received, the Trustee shall invest such moneys in a money market fund rated in the highest rating category by any nationally recognized credit rating agency, including funds for which the Trustee, its parent, its affiliates and subsidiaries provide investment advisory or other management services, if such investments are at that time authorized by California Government Code Section 53601 and, if provided to the Trustee, the Authority's investment policy. The Trustee may conclusively rely upon such written directions of the Authority as a certification that such investments constitute Investment Securities.

2. In making any investment in any Investment Securities with moneys in the 2025 Series A Issue Fund or any Account established under Section 502, the Trustee may combine such moneys with moneys in any other Fund or Account established under this Indenture of Trust but solely for the purposes of making such investment in such Investment Securities and provided that any moneys so combined shall be accounted for separately. The Trustee may act as principal or agent in the acquisition or disposition of investments.

3. 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 such Fund and the Accounts established therein, shall, to the extent that the balance then held in such Fund or Account shall exceed the requirements for deposit therein and to the extent required by the Senior Indenture, be transferred to the trustee for the Senior Bonds for deposit in the Revenue Fund and to the extent not required to be transferred to the trustee for the Senior Bonds, be transferred to the 2025 Series A Pledged Revenues Account or as otherwise instructed by an Authorized Authority Representative.

4. Nothing in this Indenture of Trust shall prevent any Investment Securities acquired as investments of funds held under this Indenture of Trust from being issued or held in book-entry form.

5. The Authority acknowledges that notwithstanding regulations of the Comptroller of the Currency or other applicable regulatory entity that may grant the Authority the right to receive brokerage confirmations of security transactions as they occur, the Authority agrees that the Trustee shall not send such confirmations to the Authority to the extent permitted by law. The Trustee will furnish the Authority periodic cash transaction statements which include detail for all investment transactions made by the Trustee hereunder.

602. Valuation and Sale of Investments.

1. Obligations purchased as an investment of moneys in the 2025 Series A Issue Fund or any Account therein created under the provisions of this Indenture of Trust shall be deemed at all times to be a part of such Fund or Account and any profit realized from the liquidation of such investment shall be credited to such Fund or Account and any loss resulting from the liquidation of such investment shall be charged to such Fund or Account.

2. In computing the amount in the 2025 Series A Issue Fund or any Account created under the provisions of this Indenture of Trust for any purpose provided in this Indenture of Trust, obligations purchased as an investment of moneys therein shall be valued at the greater of the cost of such obligations or the amortized value thereof, exclusive of accrued interest. Such computations shall be determined as of July 1 in each year.

3. Except as otherwise provided in this Indenture of Trust, the Trustee shall sell at the best price reasonably obtainable, or present for redemption, any obligation so purchased as an investment whenever it shall be directed by the Authority to do so or whenever it shall be necessary in order to provide moneys to meet any payment or transfer from any Fund or Account held by it.

4. Subject to the provisions of Section 903, the Trustee shall not be liable or responsible for making any such investment in the manner provided herein or for any loss resulting from any such investment. The Trustee may make such investment at the direction of the Authority or through the Trustee's own investment department.

ARTICLE VII

PARTICULAR COVENANTS OF THE AUTHORITY

The Authority covenants and agrees with the Trustee and the Owners as follows:

701. Payment of Bonds. The Authority shall duly and punctually pay or cause to be paid, but solely from the Pledged Revenues and amounts in the 2025 Series A Issue Fund established by this Indenture of Trust, pledged under this Indenture of Trust, the moneys held by the Fiduciaries and the proceeds of the Bonds pledged therefor by this Indenture of Trust, the principal or Redemption Price, if any, of every Bond and the interest thereon, at the dates and places and in the manner mentioned in the Bonds, according to the true intent and meaning thereof.

702. Extension of Payment of Bonds. The Authority shall not directly or indirectly extend or assent to the extension of the maturity of any of the Bonds or the time of payment of any claims for interest by the purchase or funding of such Bonds or claims for interest or by any other arrangement and in case the maturity of any of the Bonds or the time for payment of any such claims for interest shall be extended, such Bonds or claims for interest shall not be entitled, in case of any default under this Indenture of Trust, to the benefit of this Indenture of Trust or to any payment out of Pledged Revenues or the 2025 Series A Issue Fund, including the investments, if any, thereof, pledged under this Indenture of Trust or the moneys (except moneys held in trust for the payment of particular Bonds or claims for interest pursuant to this Indenture of Trust) held by the Fiduciaries, except subject to the prior payment of the principal of all Bonds Outstanding the maturity of which has not been extended and of such portion of the accrued interest on the Bonds as shall not be represented by such extended claims for interest. Nothing herein shall be deemed to limit the right of the Authority to issue refunding bonds or other evidence of indebtedness to refund the Bonds and such issuance shall not be deemed to constitute an extension of maturity of Bonds.

703. Offices for Servicing Bonds. During any period during which the book-entry system provided for by Section 309 shall not be in effect, the Authority shall at all times maintain one or more agencies in the City of Los Angeles, California, where Bonds may be presented for payment and shall at all times maintain one or more agencies where Bonds may be presented for registration of transfer or exchange, and where notices, demands and other documents may be served upon the Authority in respect of the Bonds or of this Indenture of Trust. The Authority hereby appoints the Trustee as Bond Registrar to maintain an agency for the registration of transfer or exchange of Bonds, and for the service upon the Authority of such notices, demands and other documents and the Trustee shall continuously maintain or make arrangements to provide such services. The Authority hereby appoints the Paying Agent or Agents in such city or cities as its respective agents to maintain such agencies for the payment or redemption of Bonds.

704. Further Assurance. At any and all times the Authority shall, as far as it may be authorized by law, comply with any reasonable request of the Trustee to pass, make, do, execute, acknowledge and deliver, all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, pledging, assigning and confirming in all and singular the rights, Pledged Revenues and other moneys, securities and funds hereby pledged or assigned, or intended so to be, or that the Authority may become bound to pledge or assign.

705. Power to Issue Bonds and to Pledge Pledged Revenues and Other Amounts.

1. The Authority is duly authorized under all applicable laws to create and issue the Bonds, to enter into any Parity Swaps and to execute and deliver this Indenture of Trust and to pledge the Pledged Revenues and other moneys, securities and funds purported to be subjected to the lien of this Indenture of Trust in the manner and to the extent provided in this Indenture of Trust. Except to the extent otherwise provided in this Indenture of Trust, the Pledged Revenues and other moneys, securities and funds so pledged for the benefit of the Owners of the Bonds and for any Parity Swap Providers are and will be free and clear of any pledge, lien, charge or encumbrance thereon or with respect thereto prior to, or of equal rank with, the security interest, the pledge and assignment created by this Indenture of Trust for the benefit of the Owners of the Bonds and for any such Parity Swap Providers, and all action on the part of the Authority to that end has been and will be duly and validly taken. The Bonds and the provisions of this Indenture of Trust are and will be the valid and legally enforceable obligations of the Authority in accordance with their terms and the terms of this Indenture of Trust. Subject to Section 1311, the Authority shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the Pledged Revenues and other moneys, securities and funds pledged under this Indenture of Trust and all the rights of the Owners and any Parity Swap Provider under this Indenture of Trust against all claims and demands of all persons whomsoever.

2. Notwithstanding anything to the contrary in this Indenture of Trust, no Owner of a Bond and no Parity Swap Provider shall be entitled to any interest, benefit, lien or other right in moneys or securities in the 2025 Series A Subordinate Bonds Redemption Fund.

706. Power to Establish Charges and Collect Amounts. As long as any Bonds are Outstanding, the Authority has and will have good right and lawful power to establish charges and cause to be collected amounts with respect to the use of Authority Capacity, subject to the terms of the Transmission Service Contracts.

707. Creation of Liens; Sale of Authority Capacity.

1. Except as otherwise expressly provided in this Indenture of Trust, the Authority shall not issue any bonds, notes, debentures, or other evidences of indebtedness of similar nature, other than the Bonds or Parity Swaps, payable out of or secured by a security interest in or a pledge or assignment of the Pledged Revenues or other moneys, securities or funds held or set aside by the Authority or by the Fiduciaries under this Indenture of Trust for the benefit of the Owners of the Bonds and for any Parity Swap Providers and shall not create or cause to be created any other lien or charge on the Pledged Revenues, or on such moneys, securities or funds; provided, however, that nothing herein shall preclude the issuance of any bonds, notes, debentures, evidences of indebtedness or the incurrence of any obligation (including, but not limited to, any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement) if same is payable on a basis subordinate and junior to the Bonds and the Parity Swaps, if any, and secured by a lien or charge on Pledged Revenues that is subordinate and junior to the lien of the Bonds and any such Parity Swaps on Pledged Revenues.

2. The Authority will not sell, assign or otherwise dispose of Authority Capacity or any portion thereof except as provided in the Senior Indenture. The Authority will not sell any transmission service utilizing Authority Capacity except as provided in or allowed by the Transmission Service Contracts or as allowed by applicable tax laws and regulations.

708. Annual Budget.

1. Not less than thirty (30) nor more than forty-five (45) days prior to the beginning of each Fiscal Year, the Authority shall adopt and file with the Trustee for each Fiscal Year an Annual Budget prepared in accordance with the provisions of, and in the manner contemplated by, the Transmission Service Contracts and the Senior Indenture. Each such Annual Budget shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the 2025 Series A Issue Fund, including particularly the amounts required for the accrual or payment (as applicable) of 2025 Series A Accrued Debt Service and the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps, so that the 2025 Series A Payment Account, the 2025 Series A Charges Account and the 2025 Series A Reserve Account (if funded) shall be maintained at the respective balances required by Section 504 and the provider of any Reserve Account Policy shall be repaid for any draw made under any such Reserve Account Policy for the 2025 Series A Reserve Account.

2. Following the end of each quarter of each Fiscal Year the Authority shall review its estimates set forth in the Annual Budget for such Fiscal Year, and in the event such estimates do not substantially correspond with actual revenues, expenses or other requirements, the Authority shall adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year.

3. If there are at any time during any such Fiscal Year extraordinary receipts or payments of unusual costs relating to Authority Capacity, or the amounts in the 2025 Series A Payment Account, the 2025 Series A Reserve Account and the 2025 Series A Charges Account shall be less than the respective balances required by Section 504, the Authority may promptly adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year.

4. The Authority also may at any time adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year.

5. The Trustee shall not be responsible to review the Annual Budget or any amendment thereto.

709. Charges and Enforcement.

1. The Authority shall at all times establish charges and cause to be collected amounts for the use of Authority Capacity (including amounts payable under the Transmission Service Contracts), as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment (without duplication) of all amounts required to be paid from Revenues or Available Revenues during such Fiscal Year pursuant to

the Senior Indenture, including, but not limited to, all amounts required to be paid from Pledged Revenues during such Fiscal Year pursuant to this Indenture of Trust.

2. The Authority will not furnish or supply or cause to be furnished or supplied any use or service of Authority Capacity free of charge to any person, firm or corporation, public or private, and the Authority will, subject to Section 1311, consistent with the Transmission Project Agreements, enforce the payment of any and all amounts owing to the Authority by reason of Authority Capacity by discontinuing such use or service, or by filing suit therefor, as soon as practicable after any such amounts are due, or by both such discontinuance and by filing suit.

710. Enforcement and Amendment of Transmission Service Contracts; Amendment of Senior Indenture. Subject to Section 1311, the Authority shall enforce or cause to be enforced the provisions of the Transmission Service Contracts and duly perform its covenants and agreements thereunder. The Authority will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Transmission Service Contracts that will impermissibly reduce the payments required thereunder or which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Owners under this Indenture of Trust; provided that this provision shall not prevent an amendment of any Transmission Service Contract that is expressly permitted pursuant to the provisions thereof. Except as expressly authorized in the Senior Indenture, the Authority will not consent or agree to or permit any rescission or any amendment to or otherwise take any action under or in connection with the Senior Indenture which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Owners under this Indenture of Trust.

711. Accounts and Reports.

1. The Authority shall keep or cause to be kept proper books of record and account (separate from all other records and accounts) in which complete and correct entries in all material respects shall be made of its transactions relating to the Fund and each Account established under this Indenture of Trust and that, together with the Transmission Service Contracts and all other books and papers of the Authority, including insurance policies maintained by the Authority, relating to Authority Capacity, shall at all times be subject to the inspection of the Trustee (which shall have no duty to so inspect), and the Owners of an aggregate of not less than five percent (5%) in principal amount of the Bonds then Outstanding or their representatives duly authorized in writing.

2. The Trustee shall furnish statements to the Authority promptly after the end of each month of the respective transactions during such month relating to the Fund and each Account held by it under this Indenture of Trust. The Authority shall have the right upon reasonable notice and during reasonable business hours to audit the books and records of the Trustee with respect to the Fund and Accounts held by the Trustee under this Indenture of Trust.

3. The Authority shall annually, within one hundred fifty (150) days after the close of each Fiscal Year, cause to be filed with the Trustee, and otherwise as provided by law, a copy of an annual report for such Fiscal Year, accompanied by an Accountant's Certificate,

relating to Authority Capacity and so long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, including the statements required by the Senior Indenture. So long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, such Accountant's Certificate shall state whether or not, to the knowledge of the signer, the Authority is in default with respect to any of the covenants, agreements or conditions on its part contained in this Indenture of Trust, and if so, the nature of such default. The Trustee shall not be responsible to review the financial information contained in such annual report.

4. The Authority shall file with the Trustee (a) forthwith upon becoming aware of any Event of Default or default in the performance by the Authority of any covenant, agreement or condition contained in this Indenture of Trust, a certificate of an Authorized Authority Representative specifying such Event of Default or default and (b) within one hundred fifty (150) days after the end of each Fiscal Year, commencing with the first Fiscal Year ending after the issuance of the Bonds hereunder, a certificate of an Authorized Authority Representative stating whether, to the best of the signer's knowledge and belief, the Authority has kept, observed, performed and fulfilled its covenants and obligations contained in this Indenture of Trust and whether there exists at the date of such certificate any default by the Authority under this Indenture of Trust or any Event of Default or other event that, with the lapse of time or giving of notice specified in Section 801 would become an Event of Default, and, if any such default or Event of Default or other event shall so exist, the nature and status thereof.

5. The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of this Indenture of Trust shall be available for the inspection of Owners at the office of the Trustee during business hours and with reasonable prior notice and shall be mailed to each Owner who shall file a written request therefor with the Trustee. The Trustee may charge each Owner requesting such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

712. Payment of Taxes and Charges. Subject to Section 1311, the Authority shall from time to time duly pay and discharge, or cause to be paid and discharged, all taxes, assessments and other governmental charges, or required payments in lieu thereof, lawfully imposed upon or relating to Authority Capacity or upon the rights, revenues, income, receipts, and other moneys, securities and funds of the Authority relating to Authority Capacity when the same shall become due (including all rights, moneys and other property transferred, assigned or pledged under this Indenture of Trust or the Agreements for the Acquisition of Capacity), and all lawful claims for labor and material and supplies relating to Authority Capacity, except those taxes, assessments, charges or claims that the Authority or its agent in good faith contests by proper legal proceedings if the Authority in each such case has set aside on its books reserves deemed adequate with respect thereto.

713. General; Subordination to Senior Indenture and Rights of Project Participants.

1. Subject to Section 1311, the Authority shall do and perform or cause to be done and performed all acts and things required to be done or performed by or on behalf of the Authority under the provisions of the Act and this Indenture of Trust.

2. This Indenture of Trust and the rights and privileges hereunder of the Trustee, the Owners of the Bonds and any Parity Swap Providers are specifically made subject to the provisions of the Senior Indenture and the rights of the Project Participants in the Transmission Service Contracts, provided, however, that no duties or liabilities shall be imposed on the Trustee except as specifically set forth in this Indenture of Trust.

714. 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 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 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 Bonds or, if necessary, until no longer required to maintain the excludability of interest on any 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 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.

715. Application of Available Revenues; Priority of Payment.

1. The Authority shall set aside or cause to be set aside in the General Reserve Fund under the Senior Indenture in each month Available Revenues in amounts at least sufficient to meet (a) the requirements for such month determined pursuant to Section 504 and (b) all other payments or transfers of Available Revenues required to be made in such month. On or before the last Business Day of each month the Authority shall apply or cause to be applied Available Revenues by transfer thereof from said General Reserve Fund (consistent with this subsection 1) to the 2025 Series A Pledged Revenues Account in the amount required to meet the requirements for such month determined pursuant to Section 504.

2. The Authority shall not authorize or permit any Available Revenues to be set aside, transferred or applied for any purpose pursuant to such terms and provisions or in any manner such that the setting aside, transfer or application shall have priority over or otherwise rank prior to the requirements under subsection 1 of this Section 715 for the setting aside, transferring and application of Available Revenues to meet the requirements determined pursuant to Section 504.

ARTICLE VIII

EVENTS OF DEFAULT AND REMEDIES

801. Events of Default. Each of the following shall constitute an "Event of Default" under this Indenture of Trust:

(i) except as provided in Section 406, default in the due and punctual payment of the principal or Redemption Price (if applicable) of any Bond when and as the same shall become due and payable, whether at maturity or by call for redemption, or otherwise;

(ii) default in the due and punctual payment of any installment of interest on any Bond, when and as such interest installment shall become due and payable;

(iii) default by the Authority in the performance or observance of any other of the covenants, agreements or conditions on its part in this Indenture of Trust or in the Bonds contained, and such default shall continue for a period of one hundred twenty (120) days after written notice thereof to the Authority by the Trustee or to the Authority and to the Trustee by the Owners of not less than 10% in principal amount of the Bonds Outstanding; or

(iv) the occurrence of an Event of Default (as defined in the Senior Indenture) under the Senior Indenture.

802. Accounting and Examination of Records After Default.

1. The Authority covenants that if an Event of Default shall have happened and shall not have been remedied, subject to any applicable confidentiality agreements or restrictions, the books of record and accounts of the Authority with respect to the Transmission Project and all other records of the Authority relating to Authority Capacity shall at all times be subject, during regular business hours, to the inspection and use of the Trustee and of its agents and attorneys.

2. Subject to the provisions of Section 803, the Authority covenants that if an Event of Default shall have happened and shall not have been remedied, the Authority, upon written demand of the Trustee, will account, as if it were the trustee of an express trust, for all Pledged Revenues and other moneys, securities and funds pledged or held under this Indenture of Trust for such period as shall be stated in such demand.

803. Application of Pledged Revenues and Other Moneys After Event of Default.

1. During the continuance of an Event of Default, the Trustee shall apply all moneys, securities, funds and Pledged Revenues pledged to the benefit of the Owners of the Bonds and any Parity Swap Providers (i) received by the Trustee pursuant to any right given or action taken under the provisions of this Article, and (ii) held by the Trustee pursuant and subject to the terms and conditions of this Indenture of Trust, as follows and in the following order:

First: To the payment of the reasonable fees and expenses of the Trustee for performance of its duties hereunder (including those of its counsel) including those incurred during the period of default;

Second: To the payment to the persons entitled thereto of all installments of interest on the Bonds then due in the order in which such installments became due, together with accrued and unpaid interest on the Bonds theretofore called for redemption, and, if the amount available shall not be sufficient to pay in full any installment or installments due on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Third: To the payment to the persons entitled thereto of the unpaid principal or Redemption Price (if applicable) of any Bonds that shall have become due, whether at maturity or by call for redemption, and all obligations under any Parity Swaps that shall have become due and payable (with any termination payments due under any Parity Swaps being payable on a basis subordinate and junior to the payment of the principal or Redemption Price of any Bonds), in the order of their due dates, and, if the amount available shall not be sufficient to pay in full all the Bonds and any Parity Swaps (other than termination payments thereunder) due on any date, then to the payment thereof ratably, according to the amounts of principal or Redemption Price (if applicable) or payments due under any Parity Swaps (other than termination payments thereunder) due on such date, to the persons entitled thereto, without any discrimination or preference.

2. If and whenever all overdue installments of interest on all Bonds, together with the reasonable and proper charges, expenses and liabilities of the Trustee (including without limitation reasonable fees and expenses of its attorneys), all other sums payable for the account of the Authority under this Indenture of Trust, including the principal or Redemption Price (if applicable) of and accrued unpaid interest on all Bonds that shall then be payable, and all obligations of the Authority to any Parity Swap Providers, shall be paid by or for the account of the Authority, or provision satisfactory to the Trustee and any such Parity Swap Providers, as the case may be, shall be made for such payment, and all defaults under this Indenture of Trust or the Bonds shall be made good or secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate shall be made therefor, the Trustee shall pay over to the Authority all moneys, securities, and funds then remaining unexpended in the hands of the Trustee (except moneys, securities and funds deposited or pledged, or required by the terms of this Indenture of Trust to be deposited or pledged, with the Trustee), and thereupon the Authority and the Trustee shall be restored, respectively, to their former positions and rights under this Indenture of Trust. Neither such payment by the Trustee nor such restoration of the Authority and the Trustee to their former positions and rights shall extend to or affect any subsequent default under this Indenture of Trust or impair any right consequent thereon.

804. Appointment of Receiver. Upon the occurrence of an Event of Default, and upon the filing of a suit or other commencement of judicial proceedings to enforce the rights of the Trustee and of the Owners under this Indenture of Trust, the Trustee shall be entitled to make application for the appointment of a receiver or custodian of the Pledged Revenues and of all amounts in the Fund and Accounts established by this Indenture of Trust, pending such proceedings, with such power as the court making such appointment shall confer.

805. Proceedings Brought by Trustee.

1. Subject to the provisions of Section 803, if an Event of Default shall happen and shall not have been remedied, then and in every such case, the Trustee, by its agents and attorneys, may proceed, and upon written request of the Owners of not less than a majority in aggregate principal amount of the Bonds Outstanding, to the extent indemnified as provided herein, shall proceed, to protect and enforce its rights and the rights of the Owners of the Bonds under this Indenture of Trust forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant herein contained, or in aid of the execution of any power herein granted or any remedy granted under the Act, or for an accounting against the Authority as if the Authority were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee, being advised by counsel, shall deem most effectual to enforce any of its rights or to perform any of its duties under this Indenture of Trust.

2. All rights of action under this Indenture of Trust may be enforced by the Trustee without the possession of any of the Bonds or the production thereof on the trial or other proceedings, and any such suit or proceedings instituted by the Trustee shall be brought in its name.

3. The Owners of not less than a majority in principal amount of the Bonds at the time Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any trust or power conferred upon the Trustee, provided that the Trustee shall have the right to decline to follow any such direction if the Trustee shall be advised by counsel that the action or proceeding so directed may not lawfully be taken, or if the Trustee in good faith shall determine that the action or proceeding so directed would involve the Trustee in personal liability or be unjustly prejudicial to the Owners not parties to such direction, or if the Trustee has not been indemnified to its satisfaction by the Owners.

4. Upon commencing a suit in equity or upon other commencement of judicial proceedings by the Trustee to enforce any right under this Indenture of Trust, the Trustee shall be entitled to exercise any and all rights and powers conferred in this Indenture of Trust and provided to be exercised by the Trustee upon the occurrence of any Event of Default.

5. Regardless of the happening of an Event of Default, the Trustee shall have power to, but unless requested in writing by the Owners of a majority in principal amount of the Bonds then Outstanding, and furnished with reasonable security and indemnity, shall be under no obligation to, institute and maintain such suits and proceedings as it may be advised shall be necessary or expedient to prevent any impairment of the security under this Indenture of Trust by any acts that may be unlawful or in violation of this Indenture of Trust, and such suits and proceedings as the Trustee may be advised shall be necessary or expedient to preserve or protect its interests and the interests of the Owners.

806. Restriction on Owner's Action.

1. No Owner of any Bond shall have any right to institute any suit, action or proceeding at law or in equity for the enforcement of any provision of this Indenture of Trust or the execution of any trust under this Indenture of Trust or for any remedy under this Indenture of Trust, unless such Owner shall have previously given to the Trustee written notice of the happening of an Event of Default, as provided in this Article, and the Owners of at least a majority in aggregate principal amount of the Bonds then Outstanding shall have filed a written request with the Trustee, and shall have offered it reasonable opportunity, either to exercise the powers granted in this Indenture of Trust or by the Act or by the laws of the State of California or to institute such action, suit or proceeding in its own name, and unless such Owners shall have offered to the Trustee adequate security and indemnity against the costs, expenses and liabilities to be incurred therein or thereby, and the Trustee shall have refused to comply with such request for a period of sixty (60) days after receipt by it of such notice, request and offer of indemnity, it being understood and intended that no one or more Owners of Bonds shall have any right in any manner whatsoever by his, her or their action to affect, disturb or prejudice the pledge created by this Indenture of Trust, or to enforce any right under this Indenture of Trust, except in the manner therein provided. All proceedings at law or in equity to enforce any provision of this Indenture of Trust shall be instituted, had and maintained in the manner provided in this Indenture of Trust and for the equal benefit of all Owners of the Outstanding Bonds, subject only to the provisions of Section 702.

2. Nothing in this Indenture of Trust or in the Bonds contained shall affect or impair the obligation of the Authority, which is absolute and unconditional, to pay at the respective dates of maturity and places therein expressed the principal or Redemption Price, if any, of and interest on the Bonds to the Owners thereof, or affect or impair the right of action, which is also absolute and unconditional, of any Owner to enforce such payment of his or her Bond.

807. Remedies Not Exclusive. No remedy by the terms of this Indenture of Trust conferred upon or reserved to the Trustee or the Owners is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to every other remedy given under this Indenture of Trust or existing at law, including under the Act, or in equity or by statute on or after the effective date of this Indenture of Trust.

808. Effect of Waiver and Other Circumstances.

1. No delay or omission of the Trustee or any Owner to exercise any right or power arising upon the happening of an Event of Default shall impair any right or power or shall be construed to be a waiver of any such Event of Default or be an acquiescence therein; and every power and remedy given by this Article to the Trustee or to the Owners may be exercised from time to time and as often as may be deemed expedient by the Trustee or by the Owners.

2. The Owners of not less than a majority in aggregate principal amount of the Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the Owners of all of the Bonds waive any past default under this Indenture of Trust and its consequences, except a default in the payment of interest on or principal or Redemption Price (if

applicable) of any of the Bonds. No such waiver shall extend to any subsequent or other default or impair any right consequent thereon.

809. Notice of Default. The Trustee shall promptly mail notice of the occurrence of any Event of Default to each Owner of Bonds then Outstanding at his or her address, if any, appearing upon the registry books of the Trustee.

ARTICLE IX

CONCERNING THE FIDUCIARIES

901. Trustee; Acceptance of Duties.

1. The Trustee shall signify its acceptance of the duties and obligations imposed upon it by this Indenture of Trust by executing and delivering to the Authority this Indenture of Trust and by executing such acceptance the Trustee shall be deemed to have accepted such duties and obligations, but only, however, upon the terms and conditions set forth in this Indenture of Trust.

2. The Trustee shall take all action necessary to preserve and protect the pledges and assignments of this Indenture of Trust and to enforce the obligations of the Authority with respect thereto, but only, however, upon the terms and conditions set forth in this Indenture of Trust.

902. Paying Agent; Appointment and Acceptance of Duties.

1. The Authority may appoint a Paying Agent for the Bonds and may at any time or from time to time appoint a Paying Agent having the qualifications set forth in Section 912 for a successor Paying Agent. The Authority hereby appoints U.S. Bank Trust Company, National Association as a Paying Agent for the Bonds.

2. Each Paying Agent shall signify its acceptance of the duties and obligations imposed upon it by this Indenture of Trust by executing and delivering to the Authority and to the Trustee a written acceptance thereof.

3. Unless otherwise provided, the principal corporate trust office of the Paying Agent is designated as the office or agency of the Authority for the payment of the interest on and principal or Redemption Price (if applicable) of the Bonds.

4. The Paying Agent shall perform the duties and obligations set forth in this Indenture of Trust, and in particular shall hold all sums delivered to it by the Trustee for the payment of principal or Redemption Price (if applicable) of and interest on the Bonds in trust for the benefit of the Owners thereof until such sums shall be paid to such Owners or are otherwise disposed of as herein provided.

5. In performing its duties hereunder, the Paying Agent shall be entitled to all of the rights, protections and immunities accorded to the Trustee under the terms of this Indenture of Trust.

903. Responsibilities of Fiduciaries.

1. Any recitals of fact herein and in the Bonds contained shall be taken as the statements of the Authority and no Fiduciary assumes any responsibility for the correctness of the same. No Fiduciary makes any representations as to the validity or sufficiency of this Indenture of Trust or of any Bonds issued thereunder or as to the security afforded by this Indenture of Trust, and no Fiduciary shall incur any liability in respect thereof. The Trustee shall, however, be responsible for its representation contained in its certificate of authentication on the Bonds. No Fiduciary shall be under any responsibility or duty with respect to the application of any moneys paid by such Fiduciary in accordance with the provisions of this Indenture of Trust to any other Fiduciary. No Fiduciary shall be under any obligation or duty to perform any act that would involve it in expense or liability or to institute or defend any suit in respect thereof, or to advance any of its own moneys, unless properly indemnified. Subject to the provisions of subsection 2 of this Section 903, no Fiduciary shall be liable in connection with the performance of its duties hereunder except for its own negligence, misconduct or default.

2. The Trustee, prior to the occurrence of an Event of Default and after the curing or waiver of all Events of Default that may have occurred, undertakes to perform such duties and only such duties as are specifically set forth in this Indenture of Trust. In case an Event of Default has occurred (which has not been cured or waived), the Trustee shall exercise such of the rights and powers vested in it by this Indenture of Trust, and use the same degree of care and skill in its exercise, as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. Any provision of this Indenture of Trust relating to action taken or to be taken by the Trustee or to evidence upon which the Trustee may rely shall be subject to the provisions of this Section 903.

3. The Trustee shall have no responsibility with respect to any information, statement or recital in any official statement, offering memorandum or any other disclosure material prepared or distributed with respect to the Bonds except for any information, statement or recital provided by the Trustee in writing for inclusion in any such official statement, offering memorandum or disclosure material. The Trustee shall not be deemed to have knowledge of an Event of Default hereunder unless it shall have actual knowledge of such Event of Default. The immunities extended to the Trustee also extend to its directors, officers, employees and agents. The permissive right of the Trustee to do things specified in this Indenture of Trust shall not be construed as a duty. The Trustee may execute any of the trusts or powers hereof and perform any of its duties through attorneys, agents and receivers.

904. Evidence on Which Fiduciaries May Act.

1. Each Fiduciary, upon receipt of any notice, resolution, request, consent, order, certificate, report, opinion, bond, or other paper or document furnished to it pursuant to any provision of this Indenture of Trust, shall examine such instrument to determine whether it conforms to the requirements of this Indenture of Trust and shall be protected in acting upon any such instrument believed by it in good faith to be genuine and to have been signed or presented by the proper party or parties. Each Fiduciary may consult with counsel selected with reasonable care, who may or may not be Bond Counsel, and the opinion of such counsel shall be full and complete authorization and protection in respect of any action taken or suffered by it under this Indenture of Trust in good faith and in accordance therewith.

2. Whenever any Fiduciary shall deem it necessary or desirable that a matter be proved or established prior to taking or suffering any action under this Indenture of Trust, such matter (unless other evidence in respect thereof be therein specifically prescribed) may be deemed to be conclusively proved and established by a certificate of the Authority, and such certificate shall be full warrant for any action taken or suffered in good faith under the provisions of this Indenture of Trust upon the faith thereof; but in its discretion the Fiduciary may in lieu thereof accept other evidence of such fact or matter or may require such further or additional evidence as to it may seem reasonable.

3. Except as otherwise expressly provided in this Indenture of Trust, any request, order, notice or other direction required or permitted to be furnished pursuant to any provision thereof by the Authority to any Fiduciary shall be sufficiently executed if it is executed in the name of the Authority by an Authorized Authority Representative thereof.

905. Compensation. The Authority shall cause to be paid to each Fiduciary from time to time reasonable compensation for all services rendered under this Indenture of Trust, and also all reasonable expenses, charges, counsel fees and other disbursements, including those of its attorneys, agents, and employees, incurred in and about the performance of their powers and duties under this Indenture of Trust and each Fiduciary shall have a lien therefor on any and all funds at any time held by it under this Indenture of Trust. No Fiduciary shall have any duty to risk or advance its own funds. In the event a Fiduciary advances its own funds, the Authority shall reimburse it for interest on such advances at the least of (i) the effective interest rate on the Bonds, (ii) the prime rate of such Fiduciary, and (iii) the maximum rate permitted by law. Subject to the provisions of Sections 903 and 1311, the Authority further agrees, to the extent permitted by law, to indemnify and save harmless each Fiduciary, its officers, directors, employees, and agents harmless against any costs, claims, expenses or liabilities that such Fiduciary may incur in the exercise and performance of its powers and duties hereunder that are not due to its negligence, misconduct or default. The duties of the Authority pursuant to this Section 905 shall survive the defeasance of the Bonds or any resignation or removal of any Fiduciary.

906. Certain Permitted Acts. Any Fiduciary may become the Owner of any Bonds, with the same rights it would have if it were not a Fiduciary. To the extent permitted by law, any Fiduciary may act as depositary for, and permit any of its officers or directors to act as a member of, or in any other capacity with respect to, any committee formed to protect the rights of Owners or to effect or aid in any reorganization growing out of the enforcement of the Bonds or this Indenture of Trust, whether or not any such committee represents the Owners of a majority in principal amount of the Bonds then Outstanding.

907. Resignation of Trustee. The Trustee may at any time resign and be discharged of the duties and obligations created by this Indenture of Trust by giving not less than sixty (60) days written notice to the Authority and any Parity Swap Providers, specifying the date when such resignation shall take effect, and such resignation shall take effect upon the day specified in such notice unless previously a successor shall have been appointed by the Authority with the approval of the Owners as provided in Section 909, and such successor shall have accepted such appointment, in which event such resignation shall take effect immediately upon the appointment of such successor.

908. Removal of Trustee. The Trustee may be removed at any time by (i) an instrument in writing, filed with the Trustee, signed by two Authorized Authority Representatives, unless an Event of Default has occurred and is continuing, or (ii) an instrument or concurrent instruments in writing, filed with the Trustee, and signed by the Owners of a majority in principal amount of the Bonds then Outstanding or their attorneys-in-fact duly authorized, excluding any Bonds held by or for the account of the Authority. Such removal shall take effect immediately upon the appointment of a successor as provided in Section 909 and acceptance of such appointment by such successor.

909. Appointment of Successor Trustee; Financial Qualifications of Trustee and Successor Trustee.

1. In case at any time the Trustee resigns or is removed or has become incapable of acting, or is adjudged as bankrupt or insolvent, or if a receiver, liquidator or conservator of the Trustee or of its property is appointed, or if any public officer takes charge or control of the Trustee or of its property or affairs, a successor may be appointed by the Owners of a majority in principal amount of the Bonds then Outstanding, excluding any Bonds held by or for the account of the Authority, by an instrument or concurrent instruments in writing signed and acknowledged by such Owners or by their attorneys-in-fact duly authorized and delivered to such successor Trustee, notification thereof being given to the Authority and the predecessor Trustee; provided, nevertheless, that unless a successor Trustee shall have been appointed by the Owners as aforesaid, the Authority, by a duly executed written instrument signed by an Authorized Authority Representative, shall forthwith appoint a Trustee to fill such vacancy until a successor Trustee shall be appointed by the Owners as authorized in this Section 909. Any successor Trustee appointed by the Authority shall, immediately and without further act, be superseded by a Trustee appointed by the Owners.

2. If no appointment of a successor Trustee shall be made pursuant to the foregoing provisions of this Section 909 within forty-five (45) days after the Trustee shall have given to the Authority written notice as provided in Section 907 or after a vacancy in the office of the Trustee shall have occurred by reason of its inability to act, removal, or for any other reason whatsoever, the Trustee (in the case of its resignation under Section 907) or the Owner of any Bond (in any case) may apply to any court of competent jurisdiction to appoint a successor Trustee. Said court may thereupon, after such notice, if any, as such court may deem proper, appoint a successor Trustee.

3. The Trustee appointed under the provisions of this Article or any successor to the Trustee shall be a bank, a trust company or a national banking association, doing business and having a corporate trust office in New York, New York, Los Angeles, California, or San Francisco, California, and having capital stock and surplus aggregating at least $100,000,000, if there be such a bank, trust company or national banking association willing and able to accept the office on reasonable and customary terms and authorized by law to perform all the duties imposed upon it by this Indenture of Trust.

910. Transfer of Rights and Property to Successor Trustee. Any successor Trustee appointed under this Indenture of Trust shall execute, acknowledge and deliver to its predecessor Trustee and to the Authority an instrument accepting such appointment, and thereupon such successor Trustee, without any further act, deed or conveyance, shall become fully vested with all moneys, estates, properties, rights, power, duties and obligations of such predecessor Trustee, with like effect as if originally named as Trustee; but the Trustee ceasing to act shall nevertheless, on the written request of the Authority or of the successor Trustee, execute, acknowledge, deliver, file and record such instrument of conveyance and further assurance and do such other things as may reasonably be required for more fully and certainly vesting and confirming in such successor Trustee all the right, title and interest of the predecessor Trustee in and to any property held by it under this Indenture of Trust or covered by the lien of this Indenture of Trust, and shall pay over, assign and deliver to the successor Trustee any money or other property subject to the trusts and conditions herein set forth. Should any deed, conveyance or instrument in writing from the Authority be required by such successor Trustee for more fully and certainly vesting in and confirming to such successor Trustee any such lien, estates, rights, power and duties, any and all such deeds, conveyances and instruments in writing shall, on request, and so far as may be authorized by law, be executed, acknowledged and delivered by the Authority. Any such successor Trustee shall promptly notify the Paying Agent of its appointment as Trustee.

911. Merger or Consolidation. Any company into which any Fiduciary may be merged or converted or with which it may be consolidated or any company resulting from any merger, conversion or consolidation to which it shall be a party or any company to which any Fiduciary may sell or transfer all or substantially all of its corporate trust business, provided such company shall be a bank or a trust company organized under the laws of any state of the United States of America or a national banking association and shall be authorized by law to perform all the duties imposed upon it by this Indenture of Trust, shall be the successor to such Fiduciary without the execution or filing of any paper or the performance of any further act.

912. Resignation or Removal of Paying Agent and Appointment of Successor.

1. Any Paying Agent may at any time resign and be discharged of the duties and obligations created by this Indenture of Trust by giving at least sixty (60) days' written notice to the Authority, any Parity Swap Providers, the Trustee and the other Fiduciaries. Any Paying Agent may be removed at any time by an instrument filed with such Paying Agent and the Trustee and signed by an Authorized Authority Representative. Any successor Paying Agent shall be appointed by the Authority with the approval of the Trustee and shall be a bank or a trust company organized under the laws of any state of the United States of America or a national banking association having capital stock and surplus aggregating at least $50,000,000, and willing and able to accept the office on reasonable and customary terms and authorized by law to perform all the duties imposed upon it by this Indenture of Trust.

2. In the event of the resignation or removal of any Paying Agent, such Paying Agent shall pay over, assign and deliver any moneys held by it as Paying Agent to its successor, or if there be no successor, to the Trustee. In the event that for any reason there shall be a vacancy in the office of any Paying Agent, the Trustee shall act as such Paying Agent.

ARTICLE X

SUPPLEMENTAL INDENTURES OF TRUST

1001. Supplemental Indentures of Trust Effective Upon Filing With the Trustee. For any one or more of the following purposes and at any time or from time to time, a Supplemental Indenture of Trust of the Authority may be executed and delivered by the Authority which, upon the filing with the Trustee of a copy thereof as so executed certified by an Authorized Authority Representative, shall be fully effective in accordance with its terms:

(i) to add to the covenants and agreements of the Authority in this Indenture of Trust, other covenants and agreements to be observed by the Authority that are not contrary to or inconsistent with this Indenture of Trust as theretofore in effect;

(ii) to add to the limitations and restrictions in this Indenture of Trust, other limitations and restrictions to be observed by the Authority that are not contrary to or inconsistent with this Indenture of Trust as theretofore in effect;

(iii) to confirm, as further assurance, any security interest or pledge created under this Indenture of Trust;

(iv) to modify, amend or supplement this Indenture of Trust in such manner as to permit the qualification hereof under the Trust Indenture Act of 1939, as amended, or any similar federal statute hereafter in effect, and to add such other terms, conditions and provisions as may be permitted by said act or similar federal statute, and which shall not materially and adversely affect the interests of the Owners of any of the Bonds;

(v) to modify any of the provisions of this Indenture of Trust in any other respect whatsoever, provided that (i) no Bonds shall be Outstanding at the date of the execution and delivery of such Supplemental Indenture of Trust or (ii) (a) such modification shall be, and be expressed to be, effective only after all Bonds Outstanding at the date of the execution and delivery of such Supplemental Indenture of Trust shall cease to be Outstanding, and (b) such Supplemental Indenture of Trust shall be specifically referred to in the text of all Bonds authenticated and delivered after the date of execution and delivery of such Supplemental Indenture of Trust and of Bonds issued in exchange therefor or in place thereof;

(vi) to amend, modify, or supplement this Indenture of Trust in such manner as does not materially adversely affect the rights of the Owners of the Bonds (including, but not limited to, amending, modifying or supplementing this Indenture of Trust in such manner as the Authority deems appropriate to provide for an interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement payable on a basis subordinate and junior to the Bonds and any Parity Swaps, as provided in subsection 1 of Section 707), provided that the Trustee is first furnished with an opinion of Bond Counsel to the effect that such amendment, modification or supplement is permitted under this Indenture of Trust (which permission may be pursuant to this paragraph (vi)) and shall not adversely affect the validity of the Bonds or the exclusion of interest on the Bonds from the gross income of the Owners thereof for federal income tax purposes; and

(vii) to comply with additional requirements that a Rating Agency may impose in order to issue or maintain a rating on the Bonds, provided that any Supplemental Indenture of Trust the purpose of which is to effect such changes shall be effective only upon delivery to the Authority and the Trustee of an Opinion of Bond Counsel that such changes shall not adversely affect the validity of the Bonds or the exclusion of interest on the Bonds from the gross income of the Owners thereof for federal income tax purposes.

1002. Supplemental Indentures of Trust Effective Upon Consent of Trustee. For any one or more of the following purposes and at any time or from time to time, a Supplemental Indenture of Trust may be executed and delivered by the Authority which, upon (i) the filing with the Trustee of a copy thereof as so executed certified by an Authorized Authority Representative, and (ii) the filing with the Authority of an instrument in writing made by the Trustee consenting thereto, shall be fully effective in accordance with its terms:

1. to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in this Indenture of Trust; or

2. to insert such provisions clarifying matters or questions arising under this Indenture of Trust as are necessary or desirable and are not contrary to or inconsistent with this Indenture of Trust as theretofore in effect.

1003. Supplemental Indentures of Trust Effective With Consent of Owners. At any time or from time to time, a Supplemental Indenture of Trust may be executed and delivered by the Authority subject to consent by Owners in accordance with and subject to the provisions of Article XI, which Supplemental Indenture of Trust, upon the filing with the Trustee of a copy thereof as so executed certified by an Authorized Authority Representative and upon compliance with the provisions of Article XI, shall become fully effective in accordance with its terms as provided in Article XI.

1004. General Provisions.

1. This Indenture of Trust shall not be modified or amended in any respect except as provided in and in accordance with and subject to the provisions of this Article X and Article XI. Nothing in this Article X or Article XI contained shall affect or limit the right or obligation of the Authority to adopt, make, do, execute, acknowledge or deliver any resolution, act or other instrument pursuant to the provisions of Section 704 or the right or obligation of the Authority to execute and deliver to any Fiduciary any instrument that elsewhere in this Indenture of Trust it is provided shall be delivered to said Fiduciary.

2. Any Supplemental Indenture of Trust referred to and permitted or authorized by Section 1001 or Section 1002 may be executed and delivered by the Authority without the consent of any of the Owners, but shall become effective only on the conditions, to the extent and at the time provided in said Sections, respectively. The copy of every Supplemental Indenture of Trust as executed by the Authority when filed with the Trustee shall be accompanied by an Opinion of Bond Counsel stating that such Supplemental Indenture of

Trust has been duly and lawfully executed and delivered in accordance with the provisions of this Indenture of Trust, is authorized or permitted by this Indenture of Trust, and is valid and binding upon the Authority and enforceable in accordance with its terms, subject to bankruptcy, insolvency and other laws affecting creditors' rights generally or as to the availability of any particular remedy. Upon receipt of any Supplemental Indenture of Trust referred to and permitted or authorized by Section 1001 or Section 1002 accompanied by such an Opinion of Bond Counsel, the Trustee shall execute such Supplemental Indenture of Trust.

3. The Trustee is hereby authorized to accept the delivery of any Supplemental Indenture of Trust referred to and permitted or authorized by Sections 1001, 1002 or 1003, to execute such Supplemental Indenture of Trust and to make all further agreements and stipulations as may be therein contained, and the Trustee, in taking such action, shall be fully protected in relying on an Opinion of Bond Counsel that such Supplemental Indenture of Trust is authorized or permitted by the provisions of this Indenture of Trust.

4. No Supplemental Indenture of Trust shall change or modify any of the rights or obligations hereunder of any Fiduciary without its written assent thereto.

ARTICLE XI

AMENDMENTS

1101. Mailing. Any provision in this Article for the mailing of a notice or other paper to Owners shall be fully complied with if it is mailed postage prepaid (i) to each Owner of Bonds then Outstanding at his or her address, if any, appearing upon the registry books of the Authority and (ii) to the Trustee.

1102. Powers of Amendment. Any modification or amendment of this Indenture of Trust and of the rights and obligations of the Authority and of the Owners of the Bonds thereunder, in any particular, may be made by a Supplemental Indenture of Trust, with the written consent (except as otherwise provided in Article X) given as provided in clause (a) of Section 1103 of the Owners of at least a majority in aggregate principal amount of the Bonds Outstanding at the time such consent is given, and in case less than all of Bonds then Outstanding are affected by the modification or amendment, of the Owners of at least a majority in aggregate principal amount of the Bonds so affected and Outstanding at the time such consent is given; provided, however, that if such modification or amendment by its terms will not take effect so long as any Bonds of any specified like maturity remain Outstanding the consent of the Owners of such Bonds shall not be required and such Bonds shall not be deemed to be Outstanding for the purpose of any calculation of Outstanding Bonds under this Section 1102. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any Outstanding Bond or of any installment of interest thereon or a reduction in the principal amount or the Redemption Price thereof or in the rate of interest thereon without the consent of the Owner of such Bond, or shall reduce the percentages of the consents of the Owners required to effect any such modification or amendment, or shall change or modify any of the rights or obligations of any Fiduciary without its written assent thereto. For the purposes of this Section 1102, a maturity shall be deemed to be affected by a modification or amendment of this Indenture of Trust if the same adversely affects or diminishes the rights of the Owners of Bonds of such maturity. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment Bonds of any particular maturity would be adversely affected by any modification or amendment of this Indenture of Trust and any such determination shall be binding and conclusive on the Authority and all Owners of Bonds.

1103. Consent of Owners. The Authority may at any time execute and deliver a Supplemental Indenture of Trust making a modification or amendment permitted by the provisions of Section 1102 to take effect when and as provided in this Section 1103. The Authority may fix a record date for purposes of determining Owners entitled to consent to a proposed Supplemental Indenture of Trust. A copy of such Supplemental Indenture of Trust (or brief summary thereof or reference thereto), together with a request to Owners for their consent thereto in form satisfactory to the Trustee, shall be mailed by the Trustee on behalf of the Authority to Owners (but failure to mail such copy and request shall not affect the validity of the Supplemental Indenture of Trust when consented to as in this Section 1103 provided). Such Supplemental Indenture of Trust shall not be effective unless and until there shall have been filed with the Trustee (a) the written consents of the Owners of the percentages of Outstanding Bonds specified in Section 1102 and (b) an Opinion of Bond Counsel stating that such Supplemental Indenture of Trust has been duly and lawfully executed and delivered and filed by the Authority in accordance with the provisions of this Indenture of Trust, is authorized or permitted by this Indenture of Trust, and is valid and binding upon the Authority and enforceable in accordance with its terms, subject to bankruptcy, insolvency and other laws affecting creditors' rights generally or as to the availability of any particular remedy. Each such consent shall be effective only if accompanied by proof of the holding, at the date of such consent, of the Bonds with respect to which such consent is given, which proof shall be such as is permitted by Section 1302. A certificate or certificates executed by the Trustee and filed with the Authority stating that it has examined such proof and that such proof is sufficient in accordance with Section 1302 shall be conclusive that the consents have been given by the Owners of the Bonds described in such certificate or certificates of the Trustee. Any such consent shall be binding upon the Owner of the Bonds giving such consent and, anything in Section 1302 to the contrary notwithstanding, upon any subsequent Owner of such Bonds and of any Bonds issued in exchange therefor (whether or not such subsequent Owner thereof has notice thereof) unless such consent is revoked in writing by the Owner of such Bonds giving such consent or a subsequent Owner thereof by filing with the Trustee, prior to the time when the written statement of the Trustee hereinafter in this Section 1103 provided for is filed, such revocation and, if such Bonds are transferable by delivery, proof that such Bonds are held by the signer of such revocation in the manner permitted by Section 1302. The fact that a consent has not been revoked may likewise be proved by a certificate of the Trustee filed with the Authority to the effect that no revocation thereof is on file with the Trustee. At any time after the Owners of the required percentages of Bonds shall have filed their consents to the Supplemental Indenture of Trust, the Trustee shall make and file with the Authority a written statement that the Owners of such required percentages of Bonds have filed such consents. Such written statements shall be conclusive that such consents have been so filed. At any time thereafter, notice stating in substance that the Supplemental Indenture of Trust (which may be referred to as a Supplemental Indenture of Trust executed and delivered by the Authority on a stated date, a copy of which is on file with the Trustee) has been consented to by the Owners of the required percentages of Bonds, and will be effective as provided in this Section 1103, shall be given to the Owners by the Authority by mailing such notice to the Owners, but failure to mail such notice shall not prevent such Supplemental Indenture of Trust from becoming effective. A record, consisting of the certificates or statements required or permitted by this Section 1103 to be made by the Trustee, shall be proof of the matters therein stated.

1104. Modifications by Unanimous Consent. The terms and provisions of this Indenture of Trust and the rights and obligations of the Authority and of the Owners of the Bonds hereunder may be modified or amended in any respect upon the execution and filing by the Authority of a Supplemental Indenture of Trust and the consent of the Owners of all of the Bonds then Outstanding, such consent to be given as provided in Section 1103 except that no notice to Owners by mailing shall be required; provided, however, that no such modification or amendment shall change or modify any of the rights or obligations of any Fiduciary without the filing with the Trustee of the written assent thereto of such Fiduciary in addition to the consent of the Owners.

1105. Exclusion of Bonds. Unless all Bonds Outstanding are then owned or held by the Authority, Bonds owned or held by or for the account of the Authority shall not be deemed Outstanding for the purpose of consent or other action or any calculation of Outstanding Bonds provided for in this Article XI, and the Authority shall not be entitled with respect to such Bonds to give any consent or take any other action provided for in this Article XI. At the time of any consent or other action taken under this Article XI, the Authority shall furnish the Trustee a certificate of an Authorized Authority Representative upon which the Trustee may rely, describing all Bonds so to be excluded.

1106. Notation on Bonds. Bonds authenticated and delivered after the effective date of any action taken as in Article X or this Article XI provided may, and, if the Authority so determines, shall bear a notation by endorsement or otherwise in form approved by the Authority and the Trustee as to such action, and in that case upon demand of the Owner of any Bond Outstanding at such effective date and presentation of his or her Bond for such purpose at the principal corporate trust office of the Trustee or upon any transfer or exchange of any Bond Outstanding at such effective date, suitable notation shall be made on such Bond or upon any Bond issued upon any such transfer or exchange by the Trustee as to any such action. If the Trustee shall so determine, new Bonds so modified as in the opinion of the Trustee are necessary to conform to such action shall be prepared, authenticated and delivered, and upon demand of the Owner of any Bond then Outstanding shall be exchanged, without cost to such Owner, for Bonds of the same maturity then Outstanding, upon surrender of such Bonds.

ARTICLE XII

[RESERVED]

ARTICLE XIII

MISCELLANEOUS

1301. Defeasance.

1. If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to the Owners of all Bonds the principal or Redemption Price (if applicable) of and interest due or to become due thereon, and to the Parity Swap Providers (if any) all of the amounts owed

by the Authority under any Parity Swaps, at the times and in the manner stipulated therein and in this Indenture of Trust, then the lien of this Indenture of Trust and all covenants, agreements and other obligations of the Authority to the Owners and any such Parity Swap Providers, shall thereupon cease, terminate and become void and be discharged and satisfied; provided, however, that notwithstanding anything to the contrary in this Section 1301, upon the defeasance of Bonds as provided in subsection 2 of this Section 1301, the Authority's and the Trustee's obligations under Sections 304, 305 and 306 and under Article IX shall not be discharged until such Bonds and all accrued and unpaid interest have been paid in full at the maturity thereof. In such event, the Trustee shall cause an accounting for such period or periods as shall be requested by the Authority to be prepared and filed with the Authority and, upon the request of the Authority, shall execute and deliver to the Authority all such instruments as may be desirable to evidence such discharge and satisfaction, and the Fiduciaries shall pay over or deliver, as directed by the Authority, all moneys or securities held by them pursuant to this Indenture of Trust that are not required for the payment of principal or Redemption Price (if applicable) and interest due or to become due on Bonds not theretofore surrendered for such payment or redemption.

2. Bonds (which may be less than all of the Bonds then Outstanding) or interest installments for the payment or redemption of which moneys shall have been set aside and shall be held in trust by the Paying Agents (through deposit pursuant to this Indenture of Trust of funds for such payment or redemption or otherwise) at the maturity, payment or redemption date thereof shall be deemed to have been paid within the meaning and with the effect expressed in subsection 1 of this Section 1301. Any Outstanding Bonds shall prior to the maturity or redemption date thereof be deemed to have been paid within the meaning and with the effect expressed in subsection 1 of this Section 1301 if: (a) in case any of said Bonds are to be redeemed on any date prior to their maturity, the Authority shall have given to the Trustee irrevocable instructions accepted in writing by the Trustee to mail, as provided in Article IV, notice of redemption of such Bonds on said date; (b) there shall have been deposited with the Trustee either moneys in an amount that shall be sufficient, or Defeasance Obligations (including any Defeasance Obligations issued or held in book-entry form on the books of the Department of the Treasury of the United States) the principal of and the interest on which when due will provide moneys that, together with the moneys, if any, on deposit with the Trustee, shall be sufficient, in the opinion of an independent certified public accountant or independent arbitrage consultant, to pay when due the principal or Redemption Price (if applicable) and interest due and to become due on said Bonds on and prior to the redemption date or maturity date thereof, as the case may be; and (c) in the event such Bonds are not by their terms subject to redemption within the next succeeding sixty (60) days, the Authority shall have given a trustee, which may be the Trustee, in form satisfactory to such trustee, irrevocable instructions to mail, as soon as practicable, a notice to the Owners of such Bonds that the deposit required by (b) above has been made with such trustee and that such Bonds are deemed to have been paid in accordance with this Article and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal or Redemption Price, if applicable, on such Bonds. Neither Defeasance Obligations nor moneys deposited with the Trustee pursuant to this Section 1301 nor principal or interest payments on any such Defeasance Obligations shall be withdrawn or used for any purpose other than, and shall be held in trust for, the payment of the principal or Redemption Price, if applicable, and interest on said Bonds; provided that any cash received from such principal or interest payments on such Defeasance Obligations deposited with the Trustee, (i) to the extent such cash will not be required at any time for such purpose, as

determined by an independent certified public accountant or independent arbitrage consultant, shall be paid over upon the direction of the Authority as received by the Trustee, free and clear of any trust, lien, pledge or assignment securing said Bonds or otherwise existing under this Indenture of Trust, and (ii) to the extent such cash will be required for such purpose at a later date, shall, to the extent practicable, be reinvested pursuant to the direction of the Authority in Defeasance Obligations (including any Defeasance Obligations issued or held in book-entry form on the books of the Department of the Treasury of the United States) maturing at times and in amounts sufficient to pay when due the principal or Redemption Price (if applicable) and interest to become due on said Bonds, on or prior to such redemption date or maturity date thereof, as the case may be, and interest earned from such reinvestments shall be paid over as received by the Trustee, free and clear of any lien, pledge or security interest securing said Bonds or otherwise existing under this Indenture of Trust.

1302. Evidence of Signatures of Owners and Ownership of Bonds.

1. Any request, consent, revocation of consent or other instrument that this Indenture of Trust may require or permit to be signed and executed by the Owners may be in one or more instruments of similar tenor, and shall be signed or executed by such Owners in person or by their attorneys, appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney or representative, or (ii) the holding by any person of the Bonds shall be sufficient for any purpose of this Indenture of Trust (except as otherwise therein expressly provided) if made in the following manner, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable:

(a) The fact and date of the execution by any Owner or his or her attorney of such instruments may be proved by a guarantee of the signature thereon by an eligible guarantor institution or by the certificate of any notary public or other officer authorized to take acknowledgments of deeds, that the person signing such request or other instrument acknowledged to him or her the execution thereof, or by an affidavit of a witness of such execution, duly sworn to before such notary public or other officer. Where such execution is by an officer of a corporation or association or a partner in a partnership, on behalf of such corporation, association or partnership, such signature guarantee, certificate or affidavit shall also constitute sufficient proof of his or her authority.

(b) The amount of Bonds held by any Person executing any instrument as an Owner, the date or dates of his or her holding of such Bonds, and the numbers and other identification thereof, may be proved by a certificate, which need not be acknowledged or verified, in form satisfactory to the Trustee, executed by the Trustee or by a member of a financial firm or by an officer of a bank, trust company, insurance company, financial corporation or other depositary wherever situated, showing at the date therein mentioned that such person exhibited to such member or officer or had on deposit with such depositary the Bonds described in such certificate. Such certificate may be given by a member of a financial firm or by an officer of any bank, trust company, insurance company, financial corporation or other depositary with respect to Bonds owned by it. In addition to the foregoing provisions, the Trustee may from time to time make such reasonable regulations as it may deem advisable permitting other proof of holding of Bonds transferable by delivery.

2. The ownership of Bonds and the amount, numbers and other identification, and date of holding the same, shall be proved exclusively by the registry books.

3. Any request, direction or consent by the Owner of any Bond shall bind all future Owners of such Bond in respect of anything done or suffered to be done by the Authority or any Fiduciary in accordance therewith.

1303. Moneys Held for Particular Bonds. Subject to Section 1312, the amounts held by any Fiduciary for the payment of the interest, principal or Redemption Price due on any date with respect to particular Bonds shall, on and after such date and pending such payment, be set aside on its books and held in trust by it for the Owners of the Bonds entitled thereto.

1304. Preservation and Inspection of Documents. All documents received by any Fiduciary under the provisions of this Indenture of Trust shall be retained in its possession and shall be subject at all reasonable times and with reasonable prior notice to the inspection of the Authority, any other Fiduciary, and any Owner and their agents or representatives designated in writing, any of whom may make copies thereof at their own expense.

1305. Parties Interested Herein. Nothing in this Indenture of Trust (except as may be provided in a Supplemental Indenture of Trust) expressed or implied is intended or shall be construed to confer upon, or to give to or grant to, any person or entity, other than the Authority, any Parity Swap Providers, the Fiduciaries and the Owners of the Bonds, any right, remedy or claim under or by reason of this Indenture of Trust or any covenant, condition or stipulation hereof, and all the covenants, stipulations, promises and agreements in this Indenture of Trust contained by and on behalf of the Authority shall be (except as otherwise provided in any Supplemental Indenture of Trust) for the sole and exclusive benefit of the Authority, any such Parity Swap Providers, the Fiduciaries and the Owners of the Bonds.

1306. No Recourse on the Bonds. No recourse shall be had for the payment of the principal or Redemption Price of or interest on the Bonds or for any claim based thereon or on this Indenture of Trust against the Project Participants (except as otherwise provided in the last sentence of this Section 1306), any member of the Board of Directors, officer, employee or agent of the Authority, any member of the governing body or officer of the Project Participants or any person executing the Bonds on behalf of the Authority. The Bonds shall be 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, in accordance with their terms and the provisions of this Indenture of Trust and the Thirty-First Supplemental Indenture solely by the moneys, Fund and Accounts set forth in Section 501. The payment of the principal and Redemption Price of the Bonds, and interest thereon, is not an obligation of the Project Participants, whose obligations are limited to their obligations to the Authority under the Transmission Service Contracts, including payments thereunder.

1307. Notice to Rating Agencies. The Trustee shall promptly mail notice to each Rating Agency (then rating any of the Bonds) of the occurrence of any of the following events of which it has actual knowledge or has been informed in writing of (i) any amendment or supplement to this Indenture of Trust, the Senior Indenture or any Parity Swap; (ii) any removal or resignation of the Trustee or appointment of a successor Trustee; and (iii) any redemption (if applicable) or defeasance of all Outstanding Bonds.

1308. Mailed Notices. Except as otherwise required herein, all notices required or authorized to be given to the Authority, the Trustee, the Paying Agent or any Rating Agency then rating the Bonds pursuant to this Indenture of Trust shall be in writing and shall be sent by first class mail, postage prepaid, to the following addresses, as applicable:

1. to the Authority, to:

   Southern California Public Power Authority
   1160 Nicole Court
   Glendora, California 91740
   Attention: Executive Director
   Telephone: (626) 793-9364
   Facsimile: (626) 793-9461

2. to the Trustee and Paying Agent, to:

   U.S. Bank Trust Company, National Association
   633 West Fifth Street
   24th Floor
   Los Angeles, California 90071
   Attention: Global Corporate Trust Services
   Telephone: (213) 615-6052
   Facsimile: (213) 615-6199

3. to Standard & Poor's, to:

   S&P Global Ratings
   55 Water Street
   New York, New York 10041
   Attention: Municipal Structured Surveillance
   Telephone: (212) 438-1000
   Facsimile: (212) 438-2157
   E-mail: pubfin_structured@spglobal.com

4. to Moody's, to:

   Moody's Investors Service
   7 World Trade Center at 250 Greenwich Street
   New York, New York 10007
   Attention: Public Finance Department
   Telephone: (212) 553-1658
   Facsimile: (212) 553-0882
   E-mail: MSPGSurveillance@moodys.com

5. to Fitch, to:

Fitch Ratings, Inc.
33 Whitehall Street
New York, New York 10004
Attention: Public Finance Department
Telephone: (212) 908-0500
Facsimile: (212) 480-4435
E-mail: pubfinsurv@fitchratings.com

or to such other addresses as may from time to time be furnished to the parties, effective upon the receipt of notice thereof given as set forth above.

1309. Severability of Invalid Provisions. If any one or more of the covenants or agreements provided in this Indenture of Trust on the part of the Authority or any Fiduciary to be performed should be contrary to law, then such covenant or covenants or agreement or agreements shall be deemed severable from the remaining covenants and agreements, and shall in no way affect the validity of the other provisions of this Indenture of Trust.

1310. Business Days. Except as otherwise provided herein, if the date for making any payment or the last date for performance of any act or the exercising of any right, as provided in this Indenture of Trust, is not a Business Day, such payment may be made or act performed or right exercised on the next succeeding day that is a Business Day, with the same force and effect as if done on the nominal date provided in this Indenture of Trust, and no interest shall accrue for the period from and after such nominal date.

1311. Limitation of Authority Liability. The obligations of the Authority under this Indenture of Trust as well as any costs or expenses of the Authority incurred in respect of its obligations and duties hereunder shall never 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 shall not constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit but shall be payable solely from the funds provided therefor pursuant to this Indenture of Trust. The Authority has no taxing power. It is hereby recognized and agreed that no member of the Board of Directors, no officer, employee or agent of the Authority, no member of the governing body or officer of the Project Participants and no person executing the Bonds on behalf of the Authority shall be individually liable for the Bonds or the interest thereon or in respect of any undertakings by the Authority under this Indenture of Trust.

1312. Unclaimed Moneys. Anything in this Indenture of Trust to the contrary notwithstanding, any moneys held by a Fiduciary in trust for the payment and discharge of any of the principal of, Redemption Price (if applicable) of or interest on any of the Bonds which remain unclaimed for one (1) year after the date when the payment shall have become due and payable, shall be repaid by the Fiduciary to the Authority, as its absolute property and free from trust, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Owners not yet paid shall look only to the Authority for the payment of such Bonds.

1313. Governing Law. This Indenture of Trust shall be interpreted, governed by and construed under the laws of the State of California, including the Act, as if executed and to be performed wholly within the State of California and without regard to choice of law principles that may direct the application of the laws of another jurisdiction. Each party agrees that any actions in connection with this Indenture of Trust shall be commenced in any court of competent jurisdiction in the County of Los Angeles in the State of California and each party hereby irrevocably accepts, for itself and in connection with its properties, generally and unconditionally, the exclusive jurisdiction and venue of such courts and waives any objections on the basis of *forum non conveniens* or otherwise with respect to the venue of any such action being heard in Los Angeles, California.

1314. Headings Not Binding. The headings in this Indenture of Trust are for convenience only and in no way define, limit or describe the scope or intent of any provisions or sections of this Indenture of Trust.

1315. References to Parity Swap Providers and Parity Swaps; Indenture to Remain Outstanding.

1. Any provision of this Indenture of Trust regarding Parity Swap Providers and Parity Swaps shall be deemed ineffective with respect to a particular Parity Swap Provider or Parity Swap if the Parity Swap delivered by such Parity Swap Provider is no longer in effect and no amount is due and owing by the Authority under such Parity Swap or the Parity Swap Provider is in default thereunder.

2. Notwithstanding anything to the contrary in this Indenture of Trust, this Indenture of Trust shall remain outstanding and in full force and effect for so long as any Parity Swap remains in full force and effect or any obligation is owed by the Authority thereunder.

1316. Representation by Counsel. Each of the parties was represented by its respective legal counsel during the negotiation and execution of this Indenture of Trust.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

IN WITNESS WHEREOF, Southern California Public Power Authority has caused this Indenture of Trust to be signed in its name and on its behalf by its President or any Vice President, and its corporate seal to be hereunto affixed and attested by its Secretary or Assistant Secretary, thereunto duly authorized, and to evidence its acceptance of the trusts hereby created, the Trustee has caused this Indenture of Trust to be signed in its name and on its behalf by a 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 ________________________________
Vice President

EXHIBIT A

FORM OF BOND

NO. R-__ $_________

UNLESS THIS BOND IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY, A NEW YORK CORPORATION ("DTC"), TO THE AUTHORITY OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE, OR PAYMENT, AND ANY BOND ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR IN SUCH OTHER NAME AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR TO SUCH OTHER ENTITY AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE, OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

Interest Rate	Maturity Date	Issue Date	CUSIP
%	July 1, ____	[____], 2025	842477___

REGISTERED OWNER: ----------------CEDE & CO. (TAX I.D. # 013-2555119)--------------

PRINCIPAL AMOUNT: ____________ MILLION __________ THOUSAND DOLLARS

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY (the "Authority"), established pursuant to the laws of the State of California, acknowledges itself indebted to, and for value received hereby promises to pay to the registered owner named above, or registered assigns, on the Maturity Date set forth above, but solely from the funds pledged therefor, upon surrender of this Bond at the principal corporate trust office of U.S. Bank Trust Company, National Association, St. Paul, Minnesota, as paying agent and trustee (the "Trustee") the Principal Amount set forth above in any currency of the United States of America that at the time of payment is legal tender for the payment of public and private debts, unless this Bond shall have been previously called for redemption (if applicable) in whole or in part and payment of the redemption price shall have been duly made or provided for, and to pay in like currency to the registered owner hereof interest on such principal amount by check (unless a wire transfer is requested as hereinafter permitted) mailed by first-class mail, postage prepaid, to such registered owner at such owner's address as shown on the registration books maintained by the Trustee as of the 15th day of the calendar month immediately preceding the applicable Interest Payment Date (the "Record Date"), payable on the first day of January and July in each year, commencing July 1, 2025, at the Interest Rate per annum set forth above until the Authority's obligation with respect to the payment of such principal amount shall be discharged. Interest hereon shall be computed on the basis of a 360-day year consisting of twelve 30-day months. Interest on this Bond shall accrue from the most recent Interest Payment Date on which interest has been paid or duly provided for, unless the date hereof shall be an Interest Payment Date on which interest has been paid, in which case interest shall accrue from the date hereof, or unless the date hereof is on or prior to June 15, 2025, in which case interest shall be payable from the Issue Date, or unless the date hereof is between a Record Date and the next succeeding Interest Payment Date, in which case interest shall be payable from such Interest Payment Date. Interest may be paid in immediately available funds by wire transfer on the Interest Payment Date to a designated account of any registered owner of a Bond or Bonds in an aggregate principal amount of $1,000,000 or more requesting to receive payment in such manner; provided that any such request shall be in writing and received by the Trustee prior to the Record Date immediately preceding the first Interest Payment Date to which such request is to be effective. The interest so payable on any Interest Payment Date will be paid to the person in whose name this Bond is registered at the close of business on the Record Date immediately preceding such Interest Payment Date or the date on which the principal of this Bond is to be paid.

Capitalized terms used but not defined herein shall have the meanings ascribed thereto in the Indenture of Trust (as hereinafter defined).

This Bond is registered as to both principal and interest on the registration books of the Authority, which shall be kept by the Trustee, as bond registrar, and may be transferred or exchanged, subject to the further conditions specified in the Indenture of Trust, only upon surrender hereof at the designated office of the Trustee or its agent therefor, as bond registrar, as further described below. The Bonds are issuable in denominations of $5,000 or any integral multiple thereof.

Principal and interest with respect to each Bond is secured by and payable from Pledged Revenues. The Bonds shall not be payable from and shall have no lien or charge on or pledge of the security for the Senior Bonds (including, without limitation, payments by the Project Participants under the Transmission Service Contracts for the benefit of the owners of the Senior Bonds).

The principal of, redemption price (if applicable), and interest on this Bond and the Bonds are payable solely from the funds provided for under the Indenture of Trust, subject only to the provisions of the Indenture of Trust permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture of Trust.

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 any Project Participant is pledged to the payment of the principal or redemption price hereof (if applicable) or interest on this Bond or the Bonds. Neither the payment of the principal or any part thereof or any redemption price hereof (if applicable), nor any interest hereon constitutes a debt, liability or obligation of any of the members of the Authority, and neither the State of California nor any public agency thereof, other than the Authority, nor any member of the Authority nor any Project Participant is obligated to pay the principal or redemption price (if applicable) of, or interest on, this Bond or the Bonds. This Bond shall never 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, nor shall it constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power. No member of the Board of Directors, no officer, employee or agent of the Authority, no member of the governing body or officer of the Project Participants and no person executing the Bonds on behalf of the Authority shall be individually liable for this Bond or the Bonds or the interest thereon or in respect of any undertakings by the Authority under the Indenture of Trust.

It is hereby certified and recited that all conditions, acts and things required by law and the Indenture of Trust to exist, to have happened and to have been performed precedent to and in the issuance of this Bond, exist, have happened and have been performed and that the Bonds comply in all respects with the applicable laws of the State of California, including, particularly, the Act.

This Bond shall not be entitled to any benefit under the Indenture of Trust or be valid or become obligatory for any purpose until this Bond shall have been manually authenticated by the execution by the Trustee of the Trustee's Certificate of Authentication hereon.

This Bond is one of a duly authorized issue of bonds of the Authority designated as its "Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission System")" (herein called the "Bonds"), in the aggregate principal amount of $________ 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, and any laws amendatory or supplemental thereto (the "Act") and an Indenture of Trust, dated as of [_____] 1, 2025, duly executed and delivered by the Authority to the Trustee (said Indenture of Trust, as from time to time supplemented and amended, is herein called the "Indenture of Trust"). The Bonds are subordinate in right of payment of principal and interest to the Authority's Transmission Project Revenue Bonds issued pursuant to an Indenture of Trust, dated as of May 1, 1983, as supplemented and amended from time to time, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Senior Indenture"). Copies of the Indenture of Trust and the Senior Indenture are on file at the office of the Authority and at the principal corporate trust office of the Trustee, and reference is hereby made to the Indenture of Trust and the Act for a description of the provisions, among others, with respect to the nature and extent of the security, the rights, duties and obligations of the Authority, the Trustee and the Owners of the Bonds and the terms upon which the Bonds are issued and secured under the Indenture of Trust.

The Bonds are not subject to redemption prior to maturity.

To the extent and in the manner permitted by the terms of the Indenture of Trust, the provisions of the Indenture of Trust may be modified or amended by the Authority upon the written consent of the Owners of at least a majority in aggregate principal amount of the Bonds then Outstanding under the Indenture of Trust, and, in case less than all of the Bonds then Outstanding under the Indenture of Trust would be affected thereby, of the Owners of at least a majority in aggregate principal amount of the Bonds so affected and Outstanding at such time consent is given under the Indenture of Trust; provided, however, that if such modification or amendment will, by its terms, not take effect so long as any Bonds of any specified like maturity remain Outstanding under the Indenture of Trust, the consent of the Owners of such Bonds shall not be required and such Bonds shall not be deemed to be Outstanding for the purpose of the calculation of Outstanding Bonds. No such modification or amendment shall permit a change in the terms of redemption (if subject to redemption) or maturity of the principal of any Outstanding Bond or of any installment of interest thereon or a reduction in the principal amount or redemption price thereof (if subject to redemption) or in the rate of interest thereon without the consent of the Owner of such Bond, or shall reduce the percentages of the aggregate principal amount of Bonds required to effect any such modification or amendment, or shall change or modify any of the rights or obligations of the Trustee or Paying Agent without its written assent thereto. For certain purposes as specified in the Indenture of Trust, the provisions of the Indenture of Trust may also be modified or amended by a Supplemental Indenture of Trust of the Authority executed and delivered by the Authority which, upon (i) the filing with the Trustee of a copy thereof in accordance with the Indenture of Trust, and (ii) the filing with the Authority of an instrument in writing made by the Trustee consenting thereto, shall be fully effective in accordance with its terms.

The transfer of this Bond may be registered as provided in the Indenture of Trust, only upon the books of the Authority kept for such purpose at the principal corporate trust office of the Trustee, as bond registrar, by the Owner hereof in person, or by his or her duly authorized attorney, upon surrender of this Bond together with a written instrument of transfer satisfactory to the Trustee, as bond registrar, duly executed by the Owner or his or her duly authorized attorney, and thereupon a new registered Bond or Bonds, of like tenor, in the same aggregate principal amount, maturity and interest rate, and in the same denomination, or in different Authorized Denominations equal in the aggregate to the principal amount of this Bond, shall be issued to the transferee in exchange therefor as provided in the Indenture of Trust. This Bond may, upon surrender thereof at the principal corporate trust office of the Trustee, be exchanged for an equal aggregate principal amount of Bonds of the same tenor, maturity and interest rate in such other authorized denomination or denominations as shall be requested by the Owner hereof. For every exchange or registration of transfer of Bonds, the Authority or the Trustee may impose a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect thereto. The Trustee, as bond registrar, shall not be required to register the transfer of or exchange any Bond during the 15-day period next preceding selection of Bonds for redemption (if applicable) or as to any Bond selected for redemption (if applicable). The Authority and the Trustee may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of, or on account of, the principal or redemption price, if any, hereof, and interest due hereon and for all other purposes.

Except as otherwise provided in the Indenture of Trust, if the date for making any payment or the last date for performance of any act or the exercising of any right, as provided in the Indenture of Trust, shall not be a Business Day, such payment may be made or act performed or right exercised on the next succeeding Business Day, with the same force and effect as if done on the nominal date provided in the Indenture of Trust, and no interest shall accrue for the period from and after such nominal date.

The owner of this Bond shall have no right to institute any suit, action or proceeding at law or in equity for the enforcement of any provision of the Indenture of Trust or the execution of any trust under the Indenture of Trust or for any remedy under the Indenture of Trust, except as provided in the Indenture of Trust.

IN WITNESS WHEREOF, SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY has caused this bond to be executed in its name and on its behalf by the manual or facsimile signature of its President or Vice President, and its seal (or a facsimile thereof) to be hereunto affixed, imprinted, engraved or otherwise reproduced and attested by the manual or facsimile signature of its Secretary or an Assistant Secretary, as of the date of authentication hereof.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By________________________________
President

[Seal]

Attest:__________________________________
Assistant Secretary

[FORM OF TRUSTEE'S CERTIFICATE OF AUTHENTICATION]

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This Bond is one of the Bonds delivered pursuant to the within mentioned Indenture of Trust.

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

By___________________________________
Authorized Officer

Dated: [____], 2025

[FORM OF ASSIGNMENT]

ASSIGNMENT

FOR VALUE RECEIVED the undersigned hereby sells, assigns and transfers unto ____

(Please print or type the Name and Address of
Assignee and Social Security or other identifying number)

the within Bond and all rights thereunder, and hereby irrevocably constitutes and appoints ____________________________, Attorney to register the transfer of the within Bond on the books kept for registration thereof, with full power of substitution in the premises.

Dated: ________________

____

Notice: This signature to this assignment must correspond with the name as it appears upon the face of the within Bond in every particular, without alteration or enlargement or any change whatsoever.

Signature guaranteed:

____

Signature must be guaranteed by an eligible guarantor institution.

Continuing Disclosure Undertaking
for the purpose of providing
continuing disclosure information
under Section (b)(5) of Rule 15c2-12

____, 2025

This Continuing Disclosure Undertaking (the "Agreement") is executed and delivered by the Southern California Public Power Authority (the "Authority") in connection with the issuance of its $________ Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "Bonds"). The Bonds are being issued pursuant to the Indenture of Trust, dated as of [_________] 1, 2025 (the "2025 Series A Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee").

In consideration of the issuance of the Bonds by the Authority and the purchase of such Bonds by the beneficial owners thereof, the Authority covenants and agrees as follows:

1. Purpose of This Agreement. This Agreement is executed and delivered by the Authority as of the date set forth below, for the benefit of the beneficial owners of the Bonds and in order to assist the Participating Underwriter in complying with the requirements of the Rule (as defined below). The Authority represents that it will be the only "obligated person" within the meaning of the Rule with respect to the Bonds at the time the Bonds are delivered to the Participating Underwriter and that no other person is expected to become so committed at any time after the issuance of the Bonds.

2. Definitions. (a) The terms set forth below shall have the following meanings in this Agreement, unless the context clearly otherwise requires.

"Annual Financial Information" means the financial information and operating data described in Exhibit I.

"Annual Financial Information Disclosure" means the dissemination of disclosure concerning Annual Financial Information and the dissemination of the Audited Financial Statements as set forth in Section 4.

"Audited Financial Statements" means collectively, the audited financial statements of the Authority and each Obligated Project Participant (relating to its electric utility fund), each prepared pursuant to the standards and as described in Exhibit I.

"Business Day" means any day other than (a) a Saturday or Sunday, or (b) a day on which commercial banks in New York, New York or the cities in which are located the designated corporate trust offices of the Dissemination Agent or the designated operational office of the Authority are authorized by law or executive order to close.

"Dissemination Agent" means any agent designated as such in writing by the Authority and which has filed with the Authority a written acceptance of such designation, and such agent's successors and assigns.

"EMMA" means the MSRB through its Electronic Municipal Market Access system for municipal securities disclosure or through any other electronic format or system prescribed by the MSRB for purposes of the Rule.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Final Official Statement" means the Official Statement dated _____, 2025, relating to the Bonds.

"Financial Obligation" means (a) a debt obligation, (b) a 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) a guarantee of an obligation or instrument described in clause (a) or (b) of this definition; provided however, the term Financial Obligation does not include municipal securities as to which a final official statement has been provided to the MSRB consistent with the Rule.

"MSRB" means the Municipal Securities Rulemaking Board.

"Obligated Project Participant" means the Department of Water and Power of The City of Los Angeles, the City of Anaheim and the City of Riverside.

"Participating Underwriter" means each broker, dealer or municipal securities dealer acting as an underwriter in the primary offering of the Bonds.

"Reportable Event" means the occurrence of any of the Events with respect to the Bonds set forth in Exhibit II.

"Reportable Events Disclosure" means dissemination of a notice of a Reportable Event as set forth in Section 5.

"Rule" means Rule 15c2-12 adopted by the SEC under the Exchange Act, as the same may be amended from time to time.

"SEC" means the Securities and Exchange Commission.

"Undertaking" means the obligations of the Authority pursuant to Sections 4 and 5.

(b) Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Indenture.

3. CUSIP Numbers. The CUSIP Numbers of the Bonds are as follows:

MATURITY	AMOUNT	CUSIP NUMBER
	$	

The Authority will include the CUSIP Numbers (or applicable CUSIP Number) in all disclosure described in Sections 4 and 5 of this Agreement.

4. Annual Financial Information Disclosure. Subject to Section 9 of this Agreement, the Authority hereby covenants that it will disseminate or cause to be disseminated on its behalf its Annual Financial Information and the Audited Financial Statements (in the form and by the dates set forth in Exhibit I) to EMMA in such manner and format and accompanied by identifying information as is prescribed by the MSRB or the SEC at the time of delivery of such information and by such time so that such entities receive the information by the dates specified.

If any part of the Annual Financial Information can no longer be generated because the operations to which it is related have been materially changed or discontinued, the Authority will disseminate a statement to such effect as part of the Annual Financial Information for the year in which such event first occurs.

If any amendment or waiver is made to this Agreement, the Annual Financial Information for the year in which such amendment is made (or in any notice or supplement provided to EMMA) shall contain a narrative description of the reasons for such amendment and its impact on the type of information being provided.

5. Reportable Events Disclosure. Subject to Section 8 of this Agreement, the Authority hereby covenants that it will disseminate in a timely manner (not in excess of ten business days after the occurrence of the Reportable Event) Reportable Events Disclosure to EMMA in such manner and format and accompanied by identifying information as is prescribed by the MSRB or the SEC at the time of delivery of such information. References to "material" in Exhibit II refer to materiality as it is interpreted under the Exchange Act. Notwithstanding the foregoing, notice of optional or unscheduled redemption of any Bonds or defeasance of any Bonds need not be given under this Agreement any earlier than the notice (if any) of such redemption or defeasance is given to the Bondholders pursuant to the Indenture.

6. Consequences of Failure of the Authority to Provide Information. The Authority shall give notice in a timely manner to EMMA of any failure to provide Annual Financial Information Disclosure when the same is due hereunder.

In the event of a failure of the Authority to comply with any provision of this Agreement, the beneficial owner of any Bond may seek mandamus or specific performance by court order, to cause the Authority to comply with its obligations under this Agreement. The beneficial owners of 25% or more in principal amount of the Bonds outstanding may challenge the adequacy of the information provided under this Agreement and seek specific performance by court order to cause the Authority to provide the information as required by this Agreement. A default under this Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Agreement in the event of any failure of the Authority to comply with this Agreement shall be an action to compel performance.

7. Amendments; Waiver. Notwithstanding any other provision of this Agreement, the Authority by resolution authorizing such amendment or waiver, may amend this Agreement, and any provision of this Agreement may be waived, if:

(a) (i) The amendment or waiver is made in connection with a change in circumstances that arises from a change in legal requirements, including without limitation pursuant to a "no-action" letter issued by the SEC, change in law, or change in the identity, nature, or status of the Authority, or type of business conducted; or

(ii) This Agreement, as amended, or the provision, as waived, would have complied with the requirements of the Rule at the time of the primary offering, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(b) The amendment or waiver does not materially impair the interests of the beneficial owners of the Bonds, as determined either by parties unaffiliated with the Authority (such as the Trustee), or by approving vote of Bondholders pursuant to the terms of the Indenture at the time of the amendment.

If the SEC, the MSRB or other regulatory authority approve or require Annual Financial Information Disclosure or Reportable Events Disclosure to be made to a central post office, governmental agency or similar entity other than EMMA or in lieu of EMMA, the Authority shall, if required, make such dissemination to such central post office, governmental agency or similar entity without the necessity of amending this Agreement.

8. Termination of Undertaking. The Undertaking of the Authority shall be terminated hereunder if the Authority no longer has any legal liability for any obligation on or relating to repayment of the Bonds under the Indenture. The Authority shall give notice to EMMA in a timely manner if this Section is applicable.

9. Dissemination Agent. The Authority may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Agreement, and may discharge any such Dissemination Agent with or without appointing a successor Dissemination Agent.

10. Additional Information. Nothing in this Agreement shall be deemed to prevent the Authority from disseminating any other information, using the means of dissemination set forth in this Agreement or any other means of communication, or including any other information in any Annual Financial Information Disclosure or notice of occurrence of a Reportable Event, in addition to that which is required by this Agreement. If the Authority chooses to include any information from any document or notice of occurrence of a Reportable Event in addition to that which is specifically required by this Agreement, the Authority shall have no obligation under this Agreement to update such information or include it in any future disclosure or notice of occurrence of a Reportable Event. If the name of the Authority is changed, the Authority shall disseminate such information to EMMA.

11. Beneficiaries. This Agreement has been executed in order to assist the Participating Underwriter in complying with the Rule; however, this Agreement shall inure solely to the benefit of the Authority, the Dissemination Agent, if any, and the beneficial owners of the Bonds, and shall create no rights in any other person or entity.

12. Recordkeeping. The Authority shall maintain records of all Annual Financial Information Disclosure and Reportable Events Disclosure, including the content of such disclosure, the names of the entities with whom such disclosure was filed and the date of filing such disclosure.

13. Assignment. The Authority shall not transfer its obligations under the Indenture unless the transferee agrees to assume all obligations of the Authority under this Agreement or to execute an Undertaking under the Rule.

14. Governing Law. This Agreement shall be governed by the laws of the State of California.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By ______________________________________

Daniel E. Garcia
Executive Director

EXHIBIT I

ANNUAL FINANCIAL INFORMATION AND TIMING AND AUDITED FINANCIAL STATEMENTS

"Annual Financial Information" means financial information and operating data, including:

(a) 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 Project as set forth under the section entitled "THE SOUTHERN TRANSMISSION PROJECT" and under the subsection entitled "INTERMOUNTAIN POWER PROJECT - Operating Statistics" in Appendix B; and

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

(b) 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.

(c) Updated versions of the type of information for the Anaheim Public Utilities electric system (the "Anaheim Electric System") 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 the Anaheim Electric System; and

2. the summary of financial results of the Anaheim Electric System.

(d) Updated versions of the type of information for the Riverside Public Utilities electric system (the "Riverside Electric System") 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 the Riverside Electric System; and

2. the summary of financial results of the Riverside Electric System.

(e) such other information and data as the Authority may deem necessary in order to comply with the requirements of the Rule.

"Audited Financial Statements" means the audited financial statements of the Authority and each Obligated Project Participant's electric utility fund, in each case for the most recent fiscal year (commencing with the fiscal year ended June 30, 2025), in each case prepared in accordance with generally accepted accounting principles as promulgated to comply with governmental entities from time to time (or such other accounting principles as may be applicable to the Authority and the Project Participant, as the case may be, in the future pursuant to applicable law).

All or a portion of the Annual Financial Information and the Audited Financial Statements set forth above may be included by reference to other documents which have been submitted to EMMA or filed with the SEC. If the information included by reference is contained in a final official statement, the final official statement must be available on EMMA. The final official statement need not be available from the SEC. The Authority shall clearly identify each such item of information included by reference.

Annual Financial Information with respect to each Obligated Project Participant shall be submitted to EMMA by each December 31 after the end of such Obligated Project Participant's fiscal year, commencing with the fiscal year ending June 30, 2025.

Annual Financial Information with respect to the Authority (i.e., the information described in clauses (b) and (c) of the definition of Annual Financial Information) will be submitted to EMMA by each December 31 after the end of the Authority's fiscal year, commencing with the fiscal year ending June 30, 2025.

Audited Financial Statements as described above should be filed at the same times as the Annual Financial Information for each Obligated Project Participant and the Authority. If Audited Financial Statements are not available when such Annual Financial Information is filed, unaudited financial statements shall be included.

If any change is made to the Annual Financial Information as permitted by Section 4 of the Agreement, the Authority will disseminate a notice of such change as required by Section 4.

EXHIBIT II

EVENTS WITH RESPECT TO THE BONDS
FOR WHICH REPORTABLE EVENTS DISCLOSURE IS REQUIRED

1. Principal and interest payment delinquencies

2. Non-payment related defaults, if material

3. Unscheduled draws on debt service reserves reflecting financial difficulties

4. Unscheduled draws on credit enhancements reflecting financial difficulties

5. Substitution of credit or liquidity providers, or their failure to perform

6. Adverse tax opinions, 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 security, or other material events affecting the tax status of the security

7. Modifications to the rights of security holders, if material

8. Bond calls, if material, and tender offers

9. Defeasances

10. Release, substitution or sale of property securing repayment of the securities, if material

11. Rating changes

12. Bankruptcy, insolvency, receivership or similar event of the Authority*

13. The consummation of a merger, consolidation, or acquisition involving the Authority or the sale of all or substantially all of the assets of the Authority, 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

14. Appointment of a successor or additional trustee or the change of name of a trustee, if material

15. Incurrence of a Financial Obligation of the Authority or any Obligated Project Participant (relating to its electric utility fund), if material, or agreement to covenants, events of default, remedies,

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* This event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for the obligated person in a proceeding under the U.S. 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 the obligated person, 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 the obligated person.

priority rights, or other similar terms of a Financial Obligation of the Authority, any of which affect security holders, if material

16. Default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Authority or any Obligated Project Participant (relating to its electric utility fund), any of which reflect financial difficulties.

PRELIMINARY OFFICIAL STATEMENT DATED ________, 2025

NEW ISSUE – FULL BOOK-ENTRY ONLY

Rating: Standard & Poor's: [___]
(See "RATING" 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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)

Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project)

Dated: Date of Delivery Due: July 1, as shown below

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 Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "2025 Series A Subordinate Bonds") will be issued by the Southern California Public Power Authority (the "Authority") under and pursuant to an Indenture of Trust, dated as of [_________] 1, 2025 (the "2025 Series A Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee"). The 2025 Series A Subordinate Bonds are being issued to provide moneys to refund all of the Authority's outstanding $89,480,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the "Refunded Bonds") and to pay costs of issuance relating to the 2025 Series A Subordinate Bonds. The Refunded Bonds were issued to refund the Authority's then outstanding Transmission Project Revenue Bonds (Southern Transmission Project) that were issued to finance a portion of the cost relating to the acquisition of capacity in the Southern Transmission System. See "ESTIMATED SOURCES AND USES OF FUNDS" and "THE AUTHORITY'S REFUNDING PLAN" herein.

The 2025 Series A Subordinate Bonds are being 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 2025 Series A Subordinate Bonds. Individual purchases of the 2025 Series A Subordinate Bonds will be made in book-entry form only. Purchasers of the 2025 Series A Subordinate Bonds will not receive physical certificates representing their interest in the 2025 Series A Subordinate Bonds purchased. Principal of, premium, if any, and interest on the 2025 Series A Subordinate 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 payments to its DTC participants for subsequent disbursement to the beneficial owners of the 2025 Series A Subordinate Bonds. See "BOOK-ENTRY ONLY SYSTEM" herein.

The 2025 Series A Subordinate Bonds will be issued in denominations of $5,000 and any integral multiple thereof. The 2025 Series A Subordinate Bonds will be dated their dated of delivery and will bear interest at the respective rates set forth on the inside cover hereof. Interest on the 2025 Series A Subordinate Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2025, and will be calculated on the basis of a 360-day year consisting of twelve 30-day months. The 2025 Series A Subordinate Bonds will mature on the dates and in the amounts set forth on the inside cover hereof.

The 2025 Series A Subordinate Bonds are not subject to redemption prior to maturity.

The principal of, premium if any, and interest on the 2025 Series A Subordinate Bonds are secured solely by and payable solely from Pledged Revenues (defined herein). See "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS" herein. No Senior Bonds are currently outstanding.

The 2025 Series A Subordinate Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants 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 2025 Series A Subordinate Bonds. The Authority has no taxing power.

Maturity Schedule
(see inside cover)

The 2025 Series A Subordinate Bonds are expected to be sold by competitive sale on [____], 2025, pursuant to the Notice Inviting Bids dated January [__], 2025. The 2025 Series A Subordinate Bonds are offered when, as and if issued and received by the Underwriter, 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. PFM Financial Advisors LLC is serving as Municipal Advisor to the Authority in connection with the issuance of the 2025 Series A Subordinate Bonds. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2025 Series A Subordinate Bonds. It is expected that the 2025 Series A Subordinate Bonds will be available for delivery through the facilities of DTC by Fast Automated Securities Transfer (FAST) on or about ________, 2025.

* Preliminary, subject to change.

Dated: ___________, 2025

Maturity Schedule*

$[PAR AMOUNT]
Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A
(Southern Transmission Project)

Due July 1	Principal Amount	Interest Rate	Yield	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 2025 Series A Subordinate Bonds. None of the Authority, its Municipal Advisor or the Underwriter is responsible for the selection or use of these CUSIP numbers and no representation is made as to their correctness on the 2025 Series A Subordinate 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)
Mandip Samra (Burbank)
Robert Lopez (Cerritos)
Charles Berry (Colton)
Manuel Robledo (Glendale)
Jamie L. Asbury (Imperial)
Janisse Quiñones (Los Angeles)
David Reyes (Pasadena)
David A. Garcia (Riverside)
Todd Dusenberry (Vernon)

MANAGEMENT

Tikan Singh – *President*
Todd Dusenberry – *First Vice President*
Dukku Lee – *Second Vice President*
Janisse Quiñones – *Secretary*
Peter Huynh – *Assistant Secretary*
Daniel E Garcia – *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 Anaheim
City of Riverside
City of Burbank
City of Glendale
City of Pasadena

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 Underwriter 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 Underwriter. 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 Underwriter has provided the following sentence for inclusion in this Official Statement: The Underwriter has reviewed the information in this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the accuracy or completeness of such information.

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 Marketplace (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 2025 Series A Subordinate Bonds.

References to web site 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 web sites 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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Official Statement
relating to

$[PAR AMOUNT]
Southern California Public Power Authority
(a public entity organized under the laws of the State of California)

Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

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 Project described herein and the $[PAR AMOUNT] aggregate principal amount of the Authority's Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "2025 Series A Subordinate Bonds"). The 2025 Series A Subordinate 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 Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of the State of California, and pursuant to an Indenture of Trust, dated as of [_________] 1, 2025 (the "2025 Series A Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee").

The 2025 Series A Subordinate Bonds are being issued to provide moneys to: (i) refund all of the Authority's outstanding $89,480,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (Southern Transmission Project) (the "Refunded Bonds") issued pursuant to the Indenture of Trust, dated as of March 1, 2015 (the "2015 Series C Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as successor trustee; and (ii) pay the costs of issuance relating to the 2025 Series A Subordinate Bonds. See "THE AUTHORITY'S REFUNDING PLAN."

Outstanding Bonds; Other Obligations

At the time of issuance of the 2025 Series A Subordinate Bonds, no senior lien bonds will be outstanding under the Indenture of Trust, dated as of May 1, 1983 (the "Original Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Senior Indenture Trustee"), as supplemented and amended (the "Senior Indenture"), including as supplemented and amended by the Thirty-First Supplemental Indenture of Trust relating to the 2025 Series A Subordinate Bonds, dated as of [_________] 1, 2025 (the "Thirty-First Supplemental Indenture"). Any bonds issued by the Authority pursuant to the Act and the Senior Indenture are herein referred to as the "Senior Bonds." Currently, the Authority has no Senior Bonds outstanding and no plans to issue Senior Bonds. All Senior Bonds were issued to finance or refinance payments-in-aid of construction for the Southern Transmission Project and the acquisition of the entitlements to the capability of the Southern Transmission Project from the Project Participants (as hereinafter defined). See "– Southern Transmission Project and Authority Capacity" below.

Upon the issuance of the 2025 Series A Subordinate Bonds and the defeasance of the Refunded Bonds, there will be no other subordinate bonds payable on parity with the 2025 Series A Subordinate Bonds.

Security and Sources of Payment for the 2025 Series A Subordinate Bonds; Other Obligations

Principal of, premium, if any, and interest on the 2025 Series A Subordinate Bonds will be payable from certain moneys in the General Reserve Fund under the Senior Indenture that are transferred to funds held under the 2025 Series A Subordinated Indenture. See "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS – Flow of Funds."

In addition to the 2025 Series A Subordinate Bonds and Senior Bonds, if any, additional subordinate bonds that rank on a parity with the 2025 Series A Subordinate Bonds, may be issued by the Authority. Further, interest rate swap agreements and certain other types of agreements ("Parity Swaps") payable on a parity with the 2025 Series A Subordinate Bonds (other than with respect to termination payments thereunder, which shall be payable on a basis subordinate and junior to the 2025 Series A Subordinate Bonds) may be entered into by the Trustee, the Authority and the provider of any such agreement. See "SUMMARY OF CERTAIN DOCUMENTS – SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE – Application of Revenues" and "– SUMMARY OF CERTAIN PROVISIONS OF THE 2025 SERIES A SUBORDINATED INDENTURE – Application of Pledged Revenues" in Appendix C.

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 Project are and will be performed by the Department of Water and Power of The City of Los Angeles (the "Department") pursuant to the Agency Agreement, dated as of May 1, 1983 (the "Agency Agreement"). See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Organization and Management."

Southern Transmission Project and Authority Capacity

The Senior Bonds were issued by the Authority for the purpose of financing or refinancing (i) payments-in-aid of construction made to the Intermountain Power Agency, a political subdivision of the State of Utah ("IPA"), for application to costs of acquisition and construction of a ±500-kV DC bi-pole transmission line ("HVDC transmission line") from a coal-fired, steam-electric generation station (the "Intermountain Generation Station") and switchyard located near Lynndyl, in Millard County, Utah, to Adelanto, California, 488 miles in length, together with an AC/DC converter station at each end and related microwave communication system facilities (the "Southern Transmission Project"), and (ii) the acquisition of the entitlements to the capability of the Southern Transmission Project ("Authority Capacity") from the Department and the California cities of Anaheim, Riverside, Pasadena, Burbank and Glendale (which, together with the Department, are hereinafter collectively referred to as the "Project Participants"). The HVDC transmission line is designed to have the capability of transmitting in excess of the aggregate Intermountain 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 Intermountain Generation Station dispatch, for IPP communication, and for control and protection of the

Southern Transmission Project. The microwave system facilities are located along two routes between the Intermountain Generation Station and Adelanto, forming a loop network. For selected information with respect to the largest of the Project Participants (*i.e.*, the Department and the California cities of Anaheim and Riverside), see "THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES" in Appendix A hereto.

Intermountain Power Project

IPA has constructed and placed in commercial operation the Intermountain Power Project (hereinafter, the "IPP") which consists of: (a) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,685 MW, with a reduction in the net rating to 1,665 MW as needed due to weather during June through September, and a switchyard located near Lynndyl, Utah; (b) 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; (c) the Southern Transmission Project; (d) a railcar 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 IPP.

Each Project Participant has entered into a power sales contract, as amended, with IPA obligating such Project Participant to purchase the share of IPP capacity and energy stated therein (each, an "IPP Power Sales Contract"). The IPP Power Sales Contracts obligate the Project Participants to pay their respective percentage shares of the costs of IPP on a "take-or-pay" basis. The IPP 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 Project. See "SUMMARY OF CERTAIN PROVISIONS OF THE IPP POWER SALES CONTRACTS" in Appendix C hereto.

LADWP acts as project manager and operating agent of the IPP, and is responsible for, among other things, administering, operating and maintaining the IPP.

Certain Project Participants (*i.e.*, the Department and the California cities of Burbank and Pasadena) are also project participants in the Authority's Milford Wind Corridor Phase I Project (the "Milford Phase I Project") and utilize their IPP capacity rights, under agreements relating to the IPP, to receive energy delivered from the Milford Phase I Project over the Southern Transmission System to the Adelanto Converter Station in California. Additionally, certain Project Participants (*i.e.*, the Department 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 IPP capacity rights, under agreements relating to the IPP, to receive energy delivered from the Milford Phase II Project over the Southern Transmission System to the Adelanto Converter Station in California. 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*."

Renewal of IPP 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").

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 DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – 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 is to be distinguished from the Southern Transmission Project.*

Payments-In-Aid of Construction

Pursuant to the Southern Transmission System Agreement, dated as of May 1, 1983, as amended by the First Amendment to the STS Agreement, dated as of November 1, 2008, between the Authority and IPA (as so amended and as further amended, the "STS Agreement"), the Authority agreed to make payments-in-aid of construction to IPA for all costs of acquisition and construction of the Southern Transmission Project. To the extent that payments-in-aid of construction were made and applied to the costs of acquisition and construction of the Southern Transmission Project, and IPA was not required to issue its bonds, notes or other evidences of indebtedness for such purpose, the Project Participants' payment obligations under their respective IPP Power Sales Contracts have been reduced. See "SUMMARY OF CERTAIN PROVISIONS OF THE SOUTHERN TRANSMISSION SYSTEM AGREEMENT" in Appendix C hereto.

Acquisition of Authority Capacity

The Authority and each Project Participant have entered into an Agreement for the Acquisition of Capacity, dated as of May 1, 1983 (collectively, the "Capacity Acquisition Agreements"), pursuant to which each Project Participant has assigned its entitlement to capacity of the Southern Transmission Project as set forth in its respective IPP Power Sales Contract to the Authority in return for the Authority's agreement to make payments-in-aid of construction pursuant to the STS Agreement.

Transmission Service

The Authority and each Project Participant have also entered into a Transmission Service Contract, dated as of May 1, 1983 (collectively, the "Transmission Service Contracts"). Under the Transmission Service Contracts, the Project Participants are entitled to transmission service utilizing Authority Capacity to the extent of their respective 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 Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The payment obligations under the Transmission Service Contracts 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 the Department under its Transmission Service Contract and all other of its "take-or-pay" contract obligations are payable on a parity with the Department's electric system revenue bonds (see "THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES" in Appendix A hereto) and the payment obligations of the other Project Participants under their respective 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. A failure by a Project Participant to make payments when due under its Transmission Service Contract likely would result in larger payments needing to be made by the other Project Participants. See "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS – Transmission Service Contracts" herein and "SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS" in Appendix C hereto.

The following table sets forth the Transmission Service Shares of each of the Project Participants with respect to Authority Capacity.

Project Participants	**Transmission Service 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%

Continuing Disclosure Undertaking

The Authority' will enter into a Continuing Disclosure Undertaking (the "Continuing Disclosure Undertaking"), for the benefit of the beneficial owners of the 2025 Series A Subordinate Bonds to send certain information annually and to provide notice of certain events to the MSRB's EMMA system for municipal securities disclosures, pursuant to the requirements of Section (b)(5) of Rule 15c2-12 ("Rule 15c2-12") adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended. See "CONTINUING DISCLOSURE UNDERTAKING FOR THE 2025 SERIES A SUBORDINATE BONDS."

Certain Information; Summaries and References to Documents

In preparing this Official Statement, the Authority has relied upon information relating to the Southern Transmission Project provided to the Authority by the Department 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 2025 Series A Subordinate Bonds, the 2025 Series A Subordinated Indenture, the Senior Indenture, the Transmission Service Contracts, the STS Agreement, the IPP Power Sales Contracts, the Capacity Acquisition Agreements, and certain contracts and other 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.

THE AUTHORITY'S REFUNDING PLAN

The proceeds of the 2025 Series A Subordinate Bonds, together with certain other available moneys, will provide funds to refund the Refunded Bonds. The Refunded Bonds are expected to be redeemed on [_____], 2025 (the "Redemption Date") in the principal amount of $89,480,000. The Refunded Bonds are described in the table below.

Refunded Bonds

Maturity Date (July 1)	Outstanding Principal Amount	Interest Rate	CUSIP
2025	$ 200,000	4.00%	842477UC3
2025	28,190,000	5.00	842477TY7
2026	610,000	4.00	842477UD1
2026	29,195,000	5.00	842477TZ4
2027	10,225,000	4.00	842477UE9
2027	21,030,000	5.00	842477UA7

The Refunded Bonds are expected to be called for redemption on the Redemption Date, which is also the date of delivery of the 2025 Series A Subordinate Bonds, from a portion of the proceeds of the 2025 Series A Subordinate Bonds deposited into a separate fund for the purpose of paying on the Redemption Date the redemption price (*i.e.*, 100% of the principal amount) of the Refunded Bonds together with accrued but unpaid interest to the Redemption Date.

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds relating to the 2025 Series A Subordinate Bonds are shown below:

Sources:	
Principal Amount	$
[Net] Bond Premium	
Transfers from 2015 Series C Subordinated Indenture Accounts	
Total Sources	$
Uses:	
Redemption of Refunded Bonds	$
Costs of Issuance[(1)]	
Total Uses	$

(1) Includes, among other things, Underwriter's discount, Trustee and Paying Agent fees, Bond 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 2025 Series A Subordinate Bonds are set forth in Appendix G.

DESCRIPTION OF THE 2025 SERIES A SUBORDINATE BONDS

General

The 2025 Series A Subordinate Bonds will be issued in the aggregate principal amount indicated on the cover page of this Official Statement, will be dated their date of delivery, and 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. The 2025 Series A Subordinate Bonds will be issued as fully registered bonds in the denomination of $5,000 principal amount and any integral multiple thereof. Interest on the 2025 Series A Subordinate Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2025, and will be calculated on the basis of a 360-day year consisting of twelve 30-day months. Interest on the 2025 Series A Subordinate Bonds will be paid to each Owner thereof at its 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").

The 2025 Series A Subordinate 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 the 2025 Series A Subordinate Bonds, all payments of principal of, premium, if any, and interest on such 2025 Series A Subordinate Bonds will be made directly to DTC. Disbursement of such payments to the DTC Participants (as defined below) will be the responsibility of DTC. Disbursement of such payments to the applicable Beneficial Owners (as defined below) of the 2025 Series A Subordinate Bonds will be the responsibility of the DTC Participants as more fully described herein. See "BOOK-ENTRY ONLY SYSTEM" below.

No Redemption Prior to Maturity

The 2025 Series A Subordinate Bonds are not subject to optional redemption prior to maturity.

BOOK-ENTRY ONLY SYSTEM

General

DTC will act as securities depository for the 2025 Series A Subordinate Bonds. The 2025 Series A Subordinate 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 2025 Series A Subordinate Bond will be issued for each maturity of the 2025 Series A Subordinate Bonds, each 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 2025 Series A Subordinate Bonds under the DTC book-entry system must be made by or through Direct Participants, which will receive a credit for the 2025 Series A Subordinate Bonds on DTC's records. The ownership interest of each actual purchaser of each 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds, except in the event that use of the book-entry system for the 2025 Series A Subordinate Bonds is discontinued.

To facilitate subsequent transfers, all 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds. DTC's records reflect only the identity of the Direct Participants to whose accounts such 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2025 Series A Subordinate Bonds, such as redemptions (if applicable), defaults and proposed amendments to the 2025 Series A Subordinated Indenture. For example, Beneficial Owners of 2025 Series A Subordinate Bonds may wish to ascertain that the nominee holding the 2025 Series A Subordinate 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 (if applicable) shall be sent to DTC. If less than all of the 2025 Series A Subordinate Bonds of a maturity 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal, redemption price (if applicable) and interest payments on the 2025 Series A Subordinate 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 (if applicable) 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 2025 Series A Subordinate 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, definitive 2025 Series A Subordinate Bonds 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, definitive 2025 Series A Subordinate Bonds 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 Underwriter as to the accuracy or completeness of such information, and the Authority and the Underwriter takes 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 2025 Series A Subordinate Bonds to the Beneficial Owners of the 2025 Series A Subordinate 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 applicable) of the 2025 Series A Subordinate Bonds will be payable upon surrender of such 2025 Series A Subordinate Bond at the principal corporate trust office of the Trustee (as paying agent for the 2025 Series A Subordinate Bonds) and at the office of any other paying agent hereafter appointed by the Authority; (ii) interest on the 2025 Series A Subordinate 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 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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) 2025 Series A Subordinate Bonds may be exchanged for an equal aggregate principal amount of 2025 Series A Subordinate Bonds of the same tenor, Series, maturity and interest rate in such other authorized denomination or denominations as shall be requested by such Owner, upon surrender of such 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds) will not be required to register the transfer of, or exchange, any 2025 Series A Subordinate Bonds called for redemption (if applicable), or any 2025 Series A Subordinate Bonds during the period of 15 days next preceding any selection of 2025 Series A Subordinate Bonds to be redeemed (if applicable).

SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS

Pledge Effected by the Senior Indenture

The Senior Indenture provides that the Senior Bonds, if any, are special, limited obligations of the Authority payable solely from and secured solely by, Revenues and all funds established by the Senior Indenture, including the investments, if any, thereof and the same are pledged and assigned to the Senior Indenture Trustee, for the benefit of the holders of the Senior Bonds (the "Senior Bondholders"), subject only to the provisions of the Senior Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Senior Indenture. Currently, no Senior Bonds are outstanding and the Authority currently has no plans to issue Senior Bonds. For the definition of "Revenues" as used in the preceding sentence, see "– Flow of Funds" below. The Senior Indenture also provides that the Senior Indenture will remain outstanding for so long as any Senior Bonds, the 2025 Series A Subordinate Bonds or Notes of the Authority with respect to the Southern Transmission Project remain outstanding.

See "SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE" in Appendix C hereto for further discussion of certain of the terms and provisions of the Senior Indenture.

Pledge Effected by the 2025 Series A Subordinated Indenture

The 2025 Series A Subordinate Bonds are payable from Available Revenues transferred from the General Reserve Fund of the Senior Indenture to the 2025 Series A Subordinated Indenture. The availability of Available Revenues (defined below) is subject to prior payment of all amounts payable in connection with any Senior Bonds and amounts payable from the General Reserve Fund. See "– Flow of Funds" below.

The 2025 Series A Subordinated Indenture provides that the Authority has pledged and assigned to the Trustee, for the benefit of the Owners of the 2025 Series A Subordinate Bonds and any Parity Swap Providers, (i) the Pledged Revenues and (ii) the 2025 Series A Issue Fund and all Accounts therein established by the 2025 Series A Subordinated Indenture, subject only to the provisions of the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture. Upon delivery, the 2025 Series A Subordinate Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or redemption price, if applicable, thereof and interest thereon, in accordance with their terms and the provisions of the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture, solely by the moneys, Fund and Accounts set forth in clauses (i) and (ii) of this paragraph.

"Pledged Revenues" with respect to the 2025 Series A Subordinate Bonds are all Available Revenues transferred to and deposited in the 2025 Series A Pledged Revenues Account pursuant to the Senior Indenture (including the Thirty-First Supplemental Indenture).

"Available Revenues" are all moneys and funds at any time on deposit in the General Reserve Fund established by the Senior Indenture and not required to meet a deficiency under the Senior Indenture or required by the Senior Indenture to be used for payment, purchase or redemption of Senior Bonds. As of the date of this Official Statement, there are no Senior Bonds outstanding.

See also "SUMMARY OF CERTAIN PROVISIONS OF THE 2025 SERIES A SUBORDINATED INDENTURE" in Appendix C hereto for further discussion of certain of the terms and provisions of the 2025 Series A Subordinated Indenture.

General Limitation on Obligations

The 2025 Series A Subordinate Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of any of the 2025 Series A Subordinate Bonds. The 2025 Series A Subordinate Bonds shall not constitute 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.

Transmission Service Contracts

Each Transmission Service Contract constitutes an obligation of the respective parties until the terms of all of the Transmission Service Contracts expire on June 15, 2027 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. The payment obligations under the 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 the Department under its Transmission Service Contract and all other of its "take-or-pay" contract obligations are payable on a parity with the Department's electric system revenue bonds, and the payment obligations of the other Project Participants under their respective 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.

Each Project Participant has covenanted in its 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 under its Transmission Service Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

Payments are to be made by the Project Participants on a "take-or-pay" basis, that is, whether or not the Southern Transmission Project or any part thereof has been completed, 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 whatsoever.

A failure of a Project Participant to make payments when due under its Transmission Service Contract is likely to result in larger payments needing to be made by the other Project Participants in subsequent periods for the purpose of enabling the Authority to pay operating expenses, debt service and other costs of the acquisition of Authority Capacity and to maintain any required reserves therefor. To the extent the amount to be paid by the nonpaying Project Participant is not offset by revenues from sales of transmission service derived by the Authority in respect of such non-paying Project Participant's Transmission Service Share or from any required reserves, such non-payment may result in deficits in funds under the Senior Indenture and the 2025 Series A Subordinated Indenture. In such event, the Authority would be required, in accordance with the Transmission Service Contracts, the Senior Indenture and the 2025 Series A Subordinated Indenture, to amend the Annual Budget to provide increases in subsequent billings to all Project Participants based upon Transmission Service Shares, including the non-paying Project Participant, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Project Participant's Transmission Service Share to the other Project Participants. Amounts thereafter collected from such non-paying Project Participant are to be credited against the next billing of such other Project Participants as shall be appropriate.

The Transmission Service Contracts provide that the obligations of the Project Participants under the respective 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 Senior Bonds or from Notes or other evidences of indebtedness issued in anticipation of the issuance of such Senior Bonds. Pursuant to the 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 IPP Power Sales Contracts) allocable to the Southern Transmission Project;

(2) The amounts which the Senior Indenture requires the Authority to pay or deposit during such month into funds or accounts for debt service on the Senior Bonds or reserve requirements for the Senior Bonds; and the payment of interest on Notes or other evidences of indebtedness issued in anticipation of the issuance of Senior Bonds; and

(3) One-twelfth of: the amount which the Authority is required under the Senior Indenture to pay or deposit during the then current Transmission Service Year into any other fund or account established by the Senior Indenture, including any amount needed to eliminate a deficiency in any such fund established under the Senior Indenture whether or not resulting from a default in payments by any Project Participant of amounts due under any Transmission Service Contract; the costs of providing transmission service during the then current Transmission Service Year; and 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.

Additionally, the Authority is required to make provision in the Annual Budget for each Fiscal Year for all amounts required under the 2025 Series A Subordinated Indenture to be deposited into the 2025 Series A Issue Fund (including particularly the amounts required for payment of 2025 Series A Accrued Debt Service), including particularly the amounts required for payment of Accrued Debt Service for each such series, and (without duplication) any other amounts payable under the interest rate swap agreements so that the 2025 Series A Payment Account, the 2025 Series A Reserve Account, if any, and the 2025 Series A Charges Account shall be maintained at the respective required balances.

The Senior Indenture and the 2025 Series A Subordinated Indenture require the Authority, quarterly, to review its estimates set forth in the then current Annual Budget and in the event such estimates do not substantially correspond with actual revenues, expenses or other requirements, to adopt an amended Annual Budget for the remainder of the Fiscal Year. The Authority is also required to adopt such an amended Annual Budget if there are at any time during the year extraordinary receipts or payments of unusual costs related to Authority Capacity.

The amount of Monthly Transmission Costs to be paid by each Project Participant for any month shall be its Transmission Service Share times the Monthly Transmission Costs for such month.

Within 120 days after the end of each Transmission Service Year, the Authority will submit to each Project Participant a statement of the actual amounts payable under the Transmission Service Contracts for such year and any adjustments to such amounts for any prior year, based on the annual audit required by the Transmission Service Contracts. If for any Transmission Service Year the actual amounts payable under the Transmission Service Contracts exceed the amount which the Project Participants have been billed, the Project Participants shall promptly pay the amount of such excess to the Authority; if such amounts are less than the amounts billed, the Authority will credit the excess against the Project Participants' next monthly payment.

In the event of a default or inability to perform by a Project Participant under its Transmission Service Contract, the Authority shall proceed to enforce the Project Participant's covenants or obligations thereunder, or seek damages or injunctive relief for the breach thereof, by action at law or equity. The Transmission Service Contracts also provide that if a payment due under a 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. 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 Transmission Service Contract. See "SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS" in Appendix C hereto for a discussion of certain additional provisions of the Transmission Service Contracts.

Authority Rate Covenant

Pursuant to the 2025 Series A Subordinated Indenture, the Authority has covenanted to at all times establish charges and cause to be collected amounts for the use of Authority Capacity (including amounts payable under the Transmission Service Contracts) as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment each Fiscal Year of all amounts required to be paid from Revenues or Available Revenues during such Fiscal Year pursuant to the Senior Indenture, together with all amounts required to be paid from Pledged Revenues pursuant to the 2025 Series A Subordinated Indenture.

Budgeting

The Transmission Service Contracts and the 2025 Series A Subordinated Indenture require the Authority to adopt an Annual Budget not less than 30 days prior to the beginning of each Transmission Service Year. Each Annual Budget will set forth a detailed estimate of the Monthly Transmission Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Transmission Service Year. See "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS – Transmission Service Contracts." Each Subordinated Indenture, including the 2025 Series A Subordinated Indenture, requires the Authority, following the end of each quarter of each Fiscal Year, to review its estimates set forth in the Annual Budget for such Fiscal Year and, in the event such estimates do not substantially correspond with actual revenues, expenses or other requirements, adopt an amended Annual Budget. The Authority will also adopt an amended Annual Budget, in accordance with the Transmission Service Contracts, if (i) there are at any time during the Fiscal Year extraordinary receipts or payment of unusual costs relating to Authority Capacity or (ii) the amounts in the Payment Account, the Reserve Account, if any, or the Charges Account in the Issue Fund under each Subordinated Indenture are less than the respective balances required therein by such Subordinated Indenture. The Authority may also at any time, in accordance with the provisions of the Transmission Service Contracts, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Flow of Funds

The Senior Indenture establishes the following Funds and Accounts (each of which is held by the Senior Indenture Trustee): Construction Fund, Revenue Fund, Operating Fund, Debt Service Fund (including the Debt Service Account and the Debt Service Reserve Account), Bond Anticipation Note Fund, Reserve and Contingency Fund (including the Renewal and Replacement Account and the Reserve Account) and General Reserve Fund, and several refunding escrow funds.

The 2025 Series A Subordinated Indenture establishes the 2025 Series A Issue Fund (which is held by the Trustee) and establishes within the 2025 Series A Issue Fund the following Accounts: the 2025 Series A Pledged Revenues Account, the 2025 Series A Payment Account, the 2025 Series A Reserve Account, the 2025 Series A Charges Account, the 2025 Series A Remainder Account and the 2025 Series A Costs of Issuance Account.

"Revenues" under the Senior Indenture are (i) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to Authority Capacity or to the payment of the costs thereof received or to be received by the Senior Indenture Trustee under the Transmission Service Contracts or under any other contract for the sale by the Authority of Authority Capacity or any part thereof or any contractual arrangement with respect to the use of Authority Capacity or any portion thereof or the services or capacity thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to Authority Capacity, (iii) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Senior Indenture and required to be paid into the Revenue Fund, (iv) interest received on any moneys or securities held pursuant to the 2025 Series A Subordinated Indenture and required by its terms to be paid into the Revenue Fund, (v) amounts received by or on behalf of the Authority pursuant to any Parity Swap, (vi) amounts received by or on behalf of the Authority pursuant to any subordinate swap agreement or similar agreement that provides therein (including in any schedule or attachment thereto) that payments received by or on behalf of the Authority pursuant thereto shall constitute Revenues under the Senior Indenture, and (vii) amounts received by or on behalf of the Authority pursuant to any Cap Agreement (as defined in the Senior Indenture).

Pursuant to the Senior 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 Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as reserves, equals the total moneys appropriated for Authority Operating Expenses (which include Monthly Power Costs allocable to the Southern Transmission Project) in the Annual Budget for the then current month.

(2) To the Debt Service Fund (i) for credit to the Debt Service Account, the amount, if any, required so that the balance in said Account shall equal the Accrued Aggregate Debt Service on the outstanding Senior Bonds, if any, as of the last day of the then current month; and (ii) for credit to the Debt Service Reserve Account for the outstanding Senior Bonds, if any, the amount, if any, required for such Account to equal the Debt Service Reserve Requirement for the outstanding Senior Bonds, if any, as of the last day of the then current month. There are currently no outstanding Senior Bonds.

(3) To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund, together with the amount on deposit in any fund established pursuant to the proceedings authorizing Notes and lawfully available to pay interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month, shall equal all interest accrued and unpaid and to accrue on outstanding Notes to the end of the then current calendar month. The Senior Indenture Trustee will apply amounts in the Bond Anticipation Note Fund to the payment of interest on Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Notes. There are currently no outstanding Notes.

(4) To the Reserve and Contingency Fund, for credit to the Renewal and Replacement Account and the Reserve Account, the respective amounts provided for such purposes for the then current month in the current Annual Budget.

(5) To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Authority must transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund for the Senior Bonds the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts; (b) in the event of any transfer of moneys from said Debt Service Reserve Account to said Debt Service Account for the Senior Bonds, to said Debt Service Reserve Account the amount of the deficiency in such Account resulting from such transfer; and (c) to the Renewal and Replacement Account and the Reserve Account in the Reserve and

Contingency Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts.

Thereafter, on or before the last business day of each calendar month, Available Revenues, to the extent required to be deposited into the 2025 Series A Payment Account, the 2025 Series A Reserve Account (if applicable) and the 2025 Series A Charges Account in the 2025 Series A Issue Fund for such month, are to be transferred ratably from amounts remaining in the General Reserve Fund by the Senior Indenture Trustee to the Trustee for deposit in the 2025 Series A Pledged Revenues Account. Moneys set aside to meet the requirements of the 2025 Series A Subordinated Indenture (or any future subordinated indenture) shall be applied in a manner such that none shall have priority over or otherwise rank prior to the others. Available Revenues upon their deposit in the 2025 Series A Pledged Revenues Account become Pledged Revenues, free and clear of the lien and pledge of the Senior Indenture.

Pursuant to the 2025 Series A Subordinated Indenture, as soon as practicable in each month after the deposit of Pledged Revenues into the 2025 Series A Pledged Revenues Account, but in any case no later than 12:00 noon, New York City time, on the last Business Day of such month, the Pledged Revenues are to be transferred from the 2025 Series A Pledged Revenues Account to the following Accounts in the following order of priority:

(1) To the 2025 Series A Payment Account, the amount, if any, required so that the balance in said Account shall equal the sum of (A) the 2025 Series A Accrued Debt Service as of the last day of the current month, and (B) all amounts due and payable by the Authority under any Parity Swaps (if any) during such month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account if less than the required amount).

(2) To the 2025 Series A Reserve Account, upon the occurrence of any deficiency therein (if applicable) (a) if the 2025 Series A Reserve Account is at that time funded by a Reserve Account Policy the provider of which has not failed to make payments thereunder, the amount of each unreplenished prior withdrawal from the 2025 Series A Reserve Account so that the provider of the Reserve Account Policy has been repaid for any draw made under such Policy for such Account or (b) if the 2025 Series A Reserve Account is not at that time funded by a Reserve Account Policy or, if funded by a Reserve Account Policy, the provider of such Reserve Account Policy has failed to make payment thereunder, the amount, if any, required for such Account to equal the Reserve Requirement as of the last day of the then current month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposit in clause (1) above if less than the required amount). Pursuant to the 2025 Series A Subordinated Indenture, the Reserve Requirement for the 2025 Series A Subordinate Bonds shall be equal to $0.00, and the 2025 Series A Reserve Account will not be funded.

(3) To the 2025 Series A Charges Account, the amount, if any, required so that the balance in such Account equals the sum of all amounts accrued or due and payable by the Authority as fees and charges to the Trustee or the Paying Agent during such month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposits in clauses (1) and (2) above if less than the required amount).

(4) To the 2025 Series A Remainder Account, the remaining balance, if any, of moneys in the 2025 Series A Pledged Revenues Account after making the above deposits.

No Funded 2025 Series A Reserve Account

Pursuant to the 2025 Series A Subordinated Indenture, the Reserve Requirement for the 2025 Series A Subordinate Bonds shall be equal to $0.00, and the 2025 Series A Reserve Account will not be funded.

THE PROJECT PARTICIPANTS

The Project Participants, each of which has executed a Capacity Acquisition Agreement and a Transmission Service Contract with the Authority, are the Department, the City of Anaheim, the City of Riverside, the City of Pasadena, the City of Burbank and the City of Glendale. Each Project Participant owns and operates an electric system for the distribution of electric energy to its retail customers. For information concerning the Project Participants with Transmission Service Shares exceeding 10% (*i.e.*, the Department and the California cities of Anaheim and Riverside) and their respective electric systems, 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 Executive Director, Daniel E Garcia, who was appointed to the position on May 1, 2024 and serves at the pleasure of the Board of Directors. Mr. Garcia brings 40 years of leadership and utility industry experience to the role. Mr. Garcia also serves as the Treasurer/Auditor of the Authority. He joins the Authority from the City of Riverside Public Utilities Department, where he held the position of Interim General Manager. His areas of responsibility included resource planning, strategic analytics, market operations, power generation, contracts (energy, gas and transmission), joint projects, and regulatory compliance relating to wholesale energy and transmission activities under the Federal Energy Regulatory Commission, California Independent System Operator, California Energy Commission and North American Electric Reliability Corporation. He started his utility career in 1984 as an Engineering Aide and has held various positions including System Power and Gas Dispatcher, Power Scheduler, Bulk Power Manager, and Power/Gas Procurement Manager. He joined the City of Riverside in 2007 and had served in various roles including Utilities Assistant General Manager/Resources, Market Operations Manager, Interim Planning Manager and Utilities Scheduler/Trader. Mr. Garcia holds a Bachelor of Science degree in Business Management from Woodbury 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 Agency Agreement pursuant to which the Department, 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 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 determine the cost of acquisition of Authority Capacity Interest, (iii) to formulate arrangements for the transmission of Authority Capacity to the Project Participants, (iv) to formulate the financing program and develop financing documents and (v) to acquire Authority Capacity, and (b) representing the Authority with respect to matters arising under or in connection with the Project Agreements (as defined in the Agency Agreement) or the acquisition of Authority Capacity.

Other Bond-Financed Projects of the Authority

In addition to the Southern Transmission Project, the following are the projects of the Authority that have been financed by bonds issued by the Authority. The principal of, premium, if any, and interest on the 2025 Series A Subordinate Bonds are secured solely by and payable solely from Pledged Revenues as described herein. None of the costs associated with the projects described below in this subsection is payable from such Pledged Revenues.

Southern Transmission System Renewal Project. *The Southern Transmission System Renewal Project is to be distinguished from the Southern Transmission Project, which is described below.* The

Southern Transmission System 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, the Department 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 System 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 System Renewal Project pursuant to which such Southern Transmission System 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 $1,249,045,000 aggregate principal amount of STS Renewal Bonds as of December 1, 2024.

The revenue bonds described in the immediately preceding paragraph are distinct from the revenue bonds relating to the Southern Transmission 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-Phoenix 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 $14,015,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Adelanto Project as of December 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 $11,380,000 aggregate principal amount of revenue bonds with respect to the Authority Interest (LADWP Only) in the Mead-Phoenix Project as of December 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 $207,680,000 aggregate principal amount of revenue bonds with respect to the Magnolia Power Project as of December 1, 2024 (of which $8,440,000 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 $234,360,000 aggregate principal amount of revenue bonds with respect to the Prepaid Natural Gas Project as of December 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 December 1, 2024, the Authority had outstanding $27,165,000 aggregate principal amount of revenue bonds with respect to the Natural Gas Reserves Project, consisting of $15,500,000, $8,430,000 and $3,235,000 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 December 1, 2024, the Authority had outstanding $240,980,000 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 December 1, 2024, the Authority had outstanding $148,505,000 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 December 1, 2024, the Authority had outstanding $29,500,000 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 December 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 December 1, 2024, the Authority had outstanding $64,510,000 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 December 1, 2024, the Authority had outstanding $59,435,000 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 December 1, 2024, the Authority had outstanding $192,625,000 aggregate principal amount of revenue bonds with respect to the Apex Power Project.

Clean Energy Project. The Clean Energy Project is structured to assist the California city of Anaheim, the sole project participant, to procure a long-term supply of electricity at favorable prices. In order to do so, the Clean Energy Project includes a feature whereby the Project Participant can seek to assign existing and future power purchase agreements ("PPAs") to the Authority, and the Authority may thereafter assign such PPAs to J. Aron, and if such assignment is accepted by J. Aron, electricity thereunder will be delivered to Aron Energy Prepay LLC (the "Electricity Supplier") to meet the Electricity Supplier's obligations to deliver prepaid Electricity ("Prepaid Electricity") to the Authority under a Master Power Supply Agreement (the "Master Power Supply Agreement"). The Authority will then deliver such Prepaid Electricity to Anaheim under the Clean Energy Purchase Contract (the "Clean Energy Purchase Contract") at the contract price. The Authority issued revenue bonds to finance the cost of acquisition of an approximately thirty-year supply of Prepaid Electricity under the Master Power Supply Agreement. Anaheim has entered into limited assignment agreements relating to two (2) existing power purchase agreements under which it assigned to the Authority, and the Authority assigned to J. Aron, the electricity deliveries thereunder beginning October 2024. The Authority had outstanding $592,270,000 aggregate principal amount of revenue bonds with respect to the Clean Energy Project as of December 1, 2024.

Other projects of the Authority not Financed by 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 2025 Series A Subordinate Bonds are secured solely by and payable solely from Pledged Revenues as described herein. None of the costs associated with the projects described below in this subsection is payable from such Pledged Revenues.

Projects That Have Achieved Commercial Operation

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 15, 2016. The agreement expires on December 14, 2036.

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. Additionally, 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 [December 1], 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 entered into a proposed settlement agreement (the "ARP Loyalton Settlement Agreement"), which was approved by the Authority and the other PPA buyers and submitted to the Bankruptcy Court for its approval on April 2, 2024. On May 6, 2024, the Bankruptcy Court entered an order approving of the ARP Loyalton Settlement Agreement, which settlement, among other things, (a) permitted the payment of the Authority's attorneys' fees and costs, (b) approve the Authority's and the other buyers' release of approximately $1.1. million in proceeds from four letters of credit to the trustee, and (c) obtained a release from the Chapter 7 trustee of the Authority's and the other buyers' obligations under the PPA. The trustee has filed his final reports, itemizing the payments he plans to make via check to professionals and other creditors from the proceeds of assets of the estates, and the Court is set to consider those reports on [November 6], 2024. Once those payments are made and all checks cashed, the trustee will close the cases.

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 commercial operation date for Phase 1 was November 18, 2024 and the amended expected commercial operation date for Phase 2 is March 31, 2025. The term of each agreement 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.

[Grace Orchard Solar III Project. The Authority, on behalf of the California cities of Anaheim, Colton, and Pasadena, entered into a power purchase agreement for a 170MW portion of the full output capacity of a 500 MW solar facility. The expected commercial operation date is December 1, 2027. The term for the agreement is 20 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 2025 Series A Subordinate Bonds.

THE SOUTHERN TRANSMISSION PROJECT

General Description

The Southern Transmission Project constitutes one of the components of IPP. See "INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT – INTERMOUNTAIN POWER PROJECT" in Appendix B hereto for a more detailed description of IPP.

The Southern Transmission Project 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"), 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 Project connects to the switching and transmission facilities of the Department; and (d) related microwave communication system facilities. The HVDC transmission line is designed to have the capability of transmitting in excess of the aggregate Intermountain 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 Intermountain Generation Station dispatch, for IPP communication, and for control and protection of the Southern Transmission Project. The microwave system facilities are located along two routes between the Intermountain Generation Station and Adelanto, forming a loop network.

By the execution of the Construction Management and Operating Agreement (as amended, the "Construction Management and Operating Agreement"), certain participants in IPP have designated the Department as Project Manager and Operating Agent for IPP, including the Southern Transmission Project. Actions and recommendations of the Department, in its role as Project Manager and Operating Agent, are subject to review, modification and approval by the IPP Coordinating Committee. The Department is required to construct, operate and maintain the Southern Transmission Project in accordance with prudent utility practices.

Operating Statistics

The Southern Transmission Project has operated with excellent availability and reliability. 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, 2024, transmission availability (one or both poles on) was approximately 97.30%. 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, 2024, the Project Participants received approximately 4.6 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 Project Participants.

The operating results of the Intermountain Generation Station during the last five fiscal years are shown in the following table. Based on historical experience of comparable generating units, the Authority currently expects that over the life of the plant the Intermountain Generation Station will continue to achieve the above-average levels of performance demonstrated to date. 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.

Operating Statistics

	Fiscal Year 2019-20(1)	Fiscal Year 2020-21(2)	Fiscal Year 2021-22(3)	Fiscal Year 2022-23(4)	Fiscal Year 2023-24(5)	Industry Average Calendar Years 2019-23(6)
Gross Energy Generated (MWh)						
Unit 1	3,724,186	3,808,747	3,126,525	2,764,193	2,739,388	
Unit 2	3,642,927	4,070,442	2,969,883	3,714,375	1,873,221	2,106,237
Net Energy Generated (MWh)						
Unit 1	3,443,031	3,537,724	2,873,350	2,537,344	2,496,799	
Unit 2	3,362,157	3,763,675	2,731,012	3,418,622	1,649,669	1,875,459
Plant Capacity Factor(7)						
Unit 1	43.55%	44.87%	36.45%	32.20%	31.58%	
Unit 2	42.53%	47.74%	34.64%	43.36%	20.87%	42.29%
Operating Availability(8)						
Unit 1	96.53%	85.20%	95.66%	88.07%	100.00%	
Unit 2	93.27%	94.91%	84.02%	97.16%	91.00%	80.62%
Equivalent Availability(9)						
Unit 1	96.48%	85.17%	95.66%	87.80%	100.00%	
Unit 2	93.21%	94.36%	83.87%	97.16%	90.94%	78.41%
Net Unit Heat Rate (BTU/kWh)(10)						
Unit 1	10,428	10,174	10,227	10,182	10,469	
Unit 2	10,324	10,247	10,122	10,167	10,941	10,895

(1) Reflects the following 2019-20 scheduled maintenance outages and forced outages: Unit 2 Spring (3.5 weeks) and Unit 1 Spring 2020 (8.9 days). Unplanned maintenance outages: Unit 1 (0 days) and Unit 2 (0 days); and forced outage Unit 1 (3.9 days) and Unit 2 (0.03 days). Switched unit from planned outage schedule and shortened due to COVID-19 restrictions (no U1 major outage).

(2) Reflects the following 2020-21 scheduled maintenance outages and forced outages: Unit 1 Spring (7 weeks) and Unit 2 Spring 2021 (9.2 days). Unplanned maintenance outages: Unit 1 (3.2 days) and Unit 2 (5.9 days); and forced outages: Unit 1 (0.07 days) and Unit 2 (3.4 days).

(3) Reflects the following 2021-22 scheduled maintenance outages and forced outages: Unit 2 Spring 2022 (8.3 weeks) and Unit 1 Spring 2022 (11.8 days). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (0.0 days); forced outages: Unit 1 (4.0 days) and Unit 2 (0.28 days); and reserve shutdown for coal conservation: Unit 1 (8.9 weeks) and Unit 2 (8.1 weeks).

(4) Reflects the following 2022-23 scheduled maintenance outages and forced outages: Unit 1 Spring 2023 (6.2 weeks) and Unit 2 Spring 2023 (9.9 days). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (0.0 days); and forced outages Unit 1 (4.4 hours) and Unit 2 (10.4 hours). Reserve Shutdown for coal conservation: Unit 1 (12.3 weeks) and Unit 2 (9.2 weeks).

(5) Reflects the following 2023-24 scheduled maintenance outages and forced outages: Unit 1 Spring 2024 (0.0 weeks) and Unit 2 Spring 2024 (4.4 weeks). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (1.9 days); and forced outages Unit 1 (0.00 hours) and Unit 2 (13.3 hours). Reserve Shutdown for coal conservation: Unit 1 (11.9 weeks) and Unit 2 (18.8 weeks).

(6) Industry average figures, except heat rate and energy generated, are as reported by NERC for coal-fired units rated 800-999 MW and are the composite averages of 55 units in the years for the calendar years 2019-2023. Average net station heat rate and Net Energy Generated are compiled and cited from Form EIA-923 released by the Energy Information Administration of the U.S. Department of Energy and Gross Energy Generated is compiled from the EPA Data Air Markets Program Data for 2023 for the top 25 largest western coal-fired power plants.

(7) 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.

(8) 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.

(9) 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.

(10) 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.

Arrangements for Transmission Service from Adelanto Converter Station

The Department has constructed a station and associated facilities to connect the Adelanto Converter Station with the Department's main transmission system. The Department takes delivery of its share of the Intermountain Power Project Generating Station entitlements at the Adelanto Converter Station and provides transmission service for three of the other five Participants. The Department transmits the generation entitlements of the Cities of Glendale and Burbank directly to those cities' respective systems. The Cities of Anaheim, Pasadena, and Riverside use transmission services from the California Independent System Operator ("ISO").

Additionally, certain of the Project Participants will utilize their capacity rights in the IPP Switchyard, provided under agreements relating to the IPP, to accept energy delivered from the Authority's Milford Wind Corridor Phase I Project and the Milford Wind Corridor Phase II Project, as well as from certain other projects not owned by the Authority, over the Southern Transmission System to the Adelanto terminal in California. The energy delivered at Adelanto is transmitted to the Project Participants' respective electric systems under existing transmissions service arrangements.

The rights of the Project Participants under their existing IPP agreements for the delivery of the generation entitlements over the Southern Transmission System terminate on June 15, 2027.

Permits, Licenses and Approvals

The Southern Transmission Project was 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 have been 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 years ended June 30, 2024 and June 30, 2023.

Southern California Public Power Authority
Southern Transmission System Project
Statement of Net Position
(In thousands)

	Fiscal Year Ended June 30,	
	2024	**2023**
ASSETS		
Noncurrent assets		
Net utility plant	$87,949	$91,995
Investments – restricted	26,710	54,682
Advances to IPA – restricted	10,930	10,930
Total noncurrent assets	125,589	157,607
Current assets		
Cash and cash equivalents – restricted	9,457	23,422
Cash and cash equivalents – unrestricted	391	825
Interest receivable	46	54
Accounts receivable	170	3,066
Prepaid and other assets	25	21
Total current assets	10,089	27,388
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunding	3,011	4,941
Total deferred outflows of resources	3,011	4,941
Total assets and deferred outflows of resources	$138,689	$189,936
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$92,684	$122,166
Total noncurrent liabilities	92,684	122,166
Current liabilities		
Debt due within one year	27,055	62,825
Accrued interest	2,850	4,420
Accounts payable and accruals	467	7,760
Total current liabilities	30,372	75,005
Total liabilities	123,056	197,171
NET POSITION		
Net investment in capital assets	(28,779)	(88,056)
Restricted	44,293	84,667
Unrestricted	119	(3,846)
Total net position	15,633	(7,235)
Total liabilities and net position	$138,689	$189,936

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 the fiscal years ended June 30, 2024 and June 30, 2023.

Southern California Public Power Authority
Southern Transmission System Project
Statement of Revenues, Expenses and Changes in Net Position
(In thousands)

	Fiscal Year Ended June 30,	
	2024	**2023**
Operating revenues:		
Sale of transmission services	$68,198	$102,510
Total operating revenues	68,198	102,510
Operating Expenses:		
Operations and maintenance	36,810	31,841
Depreciation, depletion, and amortization	4,046	4,046
Total operating expenses	40,856	35,887
Operating income (loss)	27,342	66,623
Non-operating revenues (expenses)		
Investment and other income	728	2,276
Other interest and debt expense	(5,202)	(7,009)
Net non-operating revenues (expenses)	(4,474)	(4,733)
Change in net position	22,868	61,890
Net position – beginning of year	(7,235)	(69,125)
Net position – end of year	$15,633	$(7,235)

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 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 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. Each Project Participant may bank allocated allowances in its compliance account to satisfy a portion of its ongoing compliance obligations. Each 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 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. Each 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. Each 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 certain 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 and the California cities of Anaheim and Riverside because they, 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 and the California city of Anaheim. 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 and the California cities of Anaheim and Riverside 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 Project Participant has approved and adopted an integrated resource plan.

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 be caused by 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. Each 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 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.

On May 13, 2024, FERC issued Order 1920 to reform the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. Order 1920, among other things, requires public utility (jurisdictional) transmission providers to conduct and periodically update long-term regional transmission planning to anticipate future needs, consider a broad set of benefits when planning new facilities, identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, propose methods of cost allocation to pay for selected long-term regional transmission facilities, and increase transparency regarding local transmission planning information. Order 1920 expands the role of states throughout the process of planning, selecting and determining how to pay for new transmission facilities.

Order 1920 reflects 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 applicable decarbonization goals.

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. In February 2024, the EPA announced that it will remove the elements that would have applied to existing natural gas-fired power plants from the final version of the rule. Instead, the EPA stated that it will commence a new rulemaking process that will apply to existing natural gas-fired plants and regulate additional pollutants. The rule relating to new gas plants and existing coal plants was finalized on April 25, 2024.

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.

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 February 7, 2024, the EPA announced a final rule to strengthen certain NAAQS for fine particulate matter. Areas that are designated as nonattainment areas have planning obligations to demonstrate attainment and meet the new standard within 6 years following the nonattainment designations.

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 2024, the EPA finalized a rule that modified regulation of coal- and oil-fired power plants, including further restricting their emissions and changing emissions monitoring requirements.

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. On May 9, 2024, the EPA finalized a supplemental rulemaking for coal-fired plants to strengthen certain wastewater discharge limits.

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 affect 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 2025 Series A Subordinate 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 each Project Participant would be precluded from reducing electric rates and charges in a manner materially and adversely affecting the payment of the 2025 Series A Subordinate 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' 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.

LITIGATION

At the time of delivery of the 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds or the collection of Pledged Revenues, or in any way questioning or affecting (i) the proceedings under which the 2025 Series A Subordinate Bonds are to be issued, (ii) the validity of any provision of the 2025 Series A Subordinate Bonds, the Senior Indenture or the 2025 Series A Subordinated Indenture, (iii) the pledge by the Authority under the 2025 Series A Subordinated Indenture, (iv) the validity or enforceability of the 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 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds nor as to the taxability of the 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds over its issue price (i.e., the first price at which price a substantial amount of such maturity of the 2025 Series A Subordinate 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 2025 Series A Subordinate 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

2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds. Prospective investors are advised to consult their own tax advisors regarding these rules.

Interest paid on tax-exempt obligations such as the 2025 Series A Subordinate 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 2025 Series A Subordinate 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 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds for federal or state income tax purposes, and thus on the value or marketability of the 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds may occur. Prospective purchasers of the 2025 Series A Subordinate Bonds should consult their own tax advisors regarding the impact of any change in law on the 2025 Series A Subordinate Bonds.

Special Tax Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the 2025 Series A Subordinate Bonds may affect the tax status of interest on the 2025 Series A Subordinate Bonds. Special Tax Counsel expresses no opinion as to any federal, state or local tax law consequences with respect to the 2025 Series A Subordinate Bonds, or the interest thereon, if any action is taken with respect to the 2025 Series A Subordinate Bonds or the proceeds thereof upon the advice or approval of other counsel.

RATING

S&P Global Ratings has assigned the 2025 Series A Subordinate Bonds the credit rating of "[___]." No application has been made to any other rating agency in order to obtain additional ratings on the 2025 Series A Subordinate Bonds. The 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 rating is not a recommendation to buy, sell or hold the 2025 Series A Subordinate Bonds. There is no assurance that 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 2025 Series A Subordinate Bonds.

UNDERWRITING

The 2025 Series A Subordinate Bonds were awarded to ________ (the "Underwriter") pursuant to a competitive bidding held on ______, 2025. The 2025 Series A Subordinate Bonds were awarded to the Underwriter, at an aggregate purchase price of $______, representing the par amount of the 2025 Series A Subordinate Bonds of $______, plus [net] original issue premium of $______, and less an

Underwriter's discount of $______. The Underwriter will be obligated to purchase all of the 2025 Series A Subordinate Bonds if any of the 2025 Series A Subordinate Bonds are purchased.

The Underwriter may offer and sell the 2025 Series A Subordinate Bonds to certain dealers (including dealers depositing 2025 Series A Subordinate 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 Underwriter.

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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 2025 Series A Subordinate 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 2025 Series A Subordinate 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 2025 Series A Subordinate Bonds is attached as Appendix F hereto. Bond Counsel will not address any of the tax aspects of the 2025 Series A Subordinate Bonds. Norton Rose Fulbright US LLP is also serving as Disclosure Counsel to the Authority in connection with the 2025 Series A Subordinate Bonds.

CONTINUING DISCLOSURE UNDERTAKING FOR THE 2025 SERIES A SUBORDINATE BONDS

The Authority will enter into a Continuing Disclosure Undertaking (the "Continuing Disclosure Undertaking") for the benefit of the beneficial owners of the 2025 Series A Subordinate Bonds to send certain information annually and to provide notice of certain events to the MSRB's EMMA system for municipal securities disclosures, pursuant to the requirements of Section (b)(5) of Rule 15c2-12 ("Rule 15c2-12") adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended.

A failure by the Authority to comply with the Continuing Disclosure Undertaking will not constitute an event of default under the Senior Indenture, the Thirty-First Supplemental Indenture, the Indenture or the 2025 Series A Subordinate Bonds and Beneficial Owners of the 2025 Series A Subordinate Bonds shall only be entitled to the remedies for any such failure described in the Continuing Disclosure Undertaking. A failure by the Authority to comply with the Continuing Disclosure Undertaking must be reported in accordance with Rule 15c2-12 and must be considered by any broker, dealer or municipal securities dealer before recommending the purchase or sale of the 2025 Series A Subordinate Bonds in the secondary market. Consequently, such a failure may adversely affect the transferability and liquidity of the 2025 Series A Subordinate Bonds and their market price. The Continuing Disclosure Undertaking and commitments of the Authority described under this heading and in APPENDIX D hereto to furnish the above-described documents and information are agreements and commitments solely of the Authority.

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 Transmission Service Contracts, the Capacity Acquisition Agreements, the STS Agreement, the IPP Power Sales Contracts, the Agency Agreement, the Senior Indenture and the 2025 Series A Subordinated Indenture are available from the Authority, 1160 Nicole Court, Glendora, California 91740.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By ____
President

APPENDIX A

THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES

The information contained in this Appendix has been furnished to the Southern California Public Power Authority (in this Appendix A, sometimes referred to as "SCPPA" in addition to the "Authority" as defined elsewhere in this Official Statement) by the respective Project Participants with Transmission Service Shares exceeding 10%. This Appendix presents information as of the respective dates set forth herein, and the applicable Project Participant makes no representations regarding the accuracy of this information subsequent to such dates. Neither the Authority nor any Project Participant makes any representation regarding the accuracy of the information contained in this Appendix other than with respect to the information relating to such Project Participant.

THE DEPARMENT 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, Chief Accounting Employee and Assistant Auditor 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, Chief Accounting Employee and Assistant Auditor 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, Ms. Janisse Quiñones, and other members of the senior management team for the Power System:

JANISSE QUIÑONES, PE, *General Manager/Chief Executive Officer and Chief Engineer.* Ms. Quiñones was named General Manager/Chief Executive Officer and Chief Engineer of the Department on April 19, 2024 and confirmed by the City Council on May 14, 2024. She has more than 25 years of leadership experience as a senior executive in utility and engineering industries. Prior to joining the Department, Ms. Quiñones was a Senior Vice President of Electric Operations at Pacific Gas and Electric Company ("PG&E"). She also previously served as Senior Vice President of Gas Engineering for PG&E, as the Vice President of Gas Systems Engineering for National Grid, and as Vice President of Operations for Cobra Acquisitions and Director of Design, Planning, Construction & Vegetation Management as part of her nine years of work at San Diego Gas & Electric ("SDG&E"). At SDG&E, Ms. Quiñones managed the majority of the company's gas and electric distribution capital construction. She currently serves as a Commander in the U.S. Coast Guard ("USCG") Reserves assigned to USCG District 11 and as the USCG Emergency Preparedness Liaison Officer where she is responsible for managing Local, State and Federal Emergencies. Ms. Quiñones previously served full time in the USCG as an Engineering Officer. She is a Professional Engineer with a Bachelor of Science degree in mechanical engineering from University of Puerto Rico-Mayaguez, a Master of Business Administration from University of Phoenix, and a Master of International Affairs from University of California, San Diego.

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. Mr. Benyamin has announced his retirement effective as of January 1, 2025.

JOHN A. SMITH, *Chief Administrative Officer*. Mr. Smith was named Chief Administrative Officer of the Department on July 1, 2024. In this capacity he will oversee support organizations that service both Water and Power Systems. He has 35 years of experience with the City of Los Angeles, including 24 years with the Department. Prior to his appointment as Chief Administrative Officer, Mr. Smith served as Director of Fleet and Aviation Services since May 2023 and previously served as Director of Facilities Services from April 2022 to May 2023. He has served in various management capacities within the Department since April 2013. He is also designated the managing responsible agent for the Department's crane inspection program licensed by the State of California Department of Industrial Relations Division of Occupational Safety and Health Crane Unit. Mr. Smith holds a Bachelor of Science degree in organizational management from the University of La Verne. Additionally, he has a Master of Science degree in management, strategy and leadership from Michigan State University.

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.

DAVID HANSON, *Interim Senior Assistant General Manager of the Power System*. Mr. Hanson was named Interim Senior Assistant General Manager of the Power System on August 14, 2024. Mr. Hanson has 22 years of experience with the Department, most recently serving as the Director of Power Construction and Maintenance within the Power System. Mr. Hanson began his career at the Department in 2002 as an Electrical Mechanic, and subsequently has held a number of supervisory and leadership positions within the Department, including Electrical Mechanic Training Center Superintendent, Manager of Construction Services and Assistant Director of Power Transmission and Distribution. Prior to joining the Department, he served his country for 10 years in the United States Navy as an Electrician's Mate First Class, Sub Surface Nuclear Power and also served as a Navy recruiter.

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, *Chief Accounting Employee and Assistant Auditor*. Mr. Huynh serves as the Chief Accounting Employee and Assistant Auditor, as well as the Assistant Chief Financial Officer and Treasurer of the Department. Mr. Huynh's appointment as Chief Accounting Employee of the Department occurred on October 8, 2024. He was previously named Assistant Chief Financial Officer and Treasurer of the Department in October 2020 and Assistant Auditor of the Department in February 2021. Before serving in those roles, 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 August 31, 2024, the Department assigned approximately 4,894 Department employees to the Power System on a full time basis. Approximately 4,569 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, expires on September 30, 2026. 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 (10) 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 69% 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, 2025 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 10(d), the Power System made contributions to the Retirement Plan of approximately $295 million in Fiscal Year 2023-24 (as part of a total Department contribution of approximately $432 million), and 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). For the Fiscal Year ending June 30, 2025, the Department budgeted a contribution of approximately $296 million from the Power Revenue Fund to the Retirement Plan (as part of a total Department contribution of approximately $435 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 "Required Supplementary Information" of the Department's Power System Financial Statements. See also specifically, Note 10(l) 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 October 1, 2024, as of July 1, 2024, the market value of the assets in the Retirement Plan was approximately $17.8 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $214.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $17.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $426.2 million. As of July 1, 2024, the Retirement Plan had unrecognized investment gain of approximately $212.0 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 gain for the year ended June 30, 2024 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2024-25 would decrease from approximately 28.0% of total Department covered payroll to 26.6% of total Department covered payroll. Additionally, if the net deferred gain 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, 2024 would increase from approximately 97.6% to 98.8%.

According to the 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%.

Contribution requirements for the Fiscal Year ending June 30, 2025 were set based on the asset values as of June 30, 2024. 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 October 1, 2024, the estimated contribution for Fiscal Year 2024-25 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, was 11.29% for Tier 2 (as compared to 21.13% for Tier 1). As of the July 1, 2024 actuarial valuation report, 58% 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 (11) 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 (11)(d), the Power System paid Healthcare Benefits of approximately $72.2 million in Fiscal Year 2023-24 (as part of a total Department contribution of approximately $110.3 million), and 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). For the Fiscal Year ending June 30, 2025, the Department budgeted approximately $86.9 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $131.7million).

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 October 31, 2024, as of June 30, 2024 , 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 $76.1 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 $28.8 million. As of June 30, 2024, the Healthcare Benefits had unrecognized investment gains of approximately $47.3 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, 2024, the ratio of the actuarial value of assets to actuarial accrued liabilities decreased from 114.16% as of June 30, 2023 to 100.90% as of June 30, 2024. On a market value of assets basis, the funded ratio decreased from 113.17% as of June 30, 2023 to 102.38% as of June 30, 2024. The unfunded actuarial accrued liability (on an actuarial value of assets basis) increased from a surplus of $371.7 million as of June 30, 2023 to a surplus of $28.8 million as of June 30, 2024.

According to the 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.

Contribution requirements for the Fiscal Year ending June 30, 2025 were set based on the asset values as of June 30, 2024. 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 October 31, 2024, for Fiscal Year 2024-25, the Normal Cost, as a percentage of payroll, was estimated to be 5.83% for Tier 2 (as compared to 5.04% 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, 2024, the Power System had a net OPEB liability surplus of $160.2 million comprised of $233.7 million surplus of retiree medical and $73.5 million liability in death benefits. 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 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 "Required Supplementary Information" in the Department's Power System Financial Statements. See also specifically, Note 11(j) 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.

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, 2020 – 2024
($ in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2020	$229,913
2021	218,355
2022	225,015
2023	232,043
2024	244,695

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.

Insurance

The Department's insurance program generally 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 $100 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 $105.5 million of commercial wildfire insurance, totaling an insurance tower of $205.5 million.

To complement its overall wildfire insurance program, the Department augments and supports its wildfire coverage with a CAT Bond. The previous $31.5 million indemnity wildfire CAT Bond, lasted for a three-year period, September 2021 to September 2024, and utilized an attachment point at $125 million. The CAT Bond is intended to cover a portion of any large claim for a fire event during the coverage period 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. The Department is currently pursuing a new CAT Bond issue of at least $50 million with an attachment point at $100 million. Through the utilization of commercial insurance and self-insurance, the wildfire insurance program currently has a total limit of $205.5 million available for wildfire losses. Once the pending CAT Bond issue is complete, it is expected to add at least $50 million.

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, 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 pending CAT Bond issuance, the Department continues to maintain a bona fide program of self-insurance as well. As of August 31, 2024, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $232.5 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 Marketplace Substation, 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, 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 [May 31], 2024. *{update to come}*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 [May 31], 2024, the debt reduction trust fund had a balance of approximately $513.3 million (investments at fair market value as of such date). *{update to come}*

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.

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POWER SYSTEM TRUST FUNDS INVESTMENTS
ASSETS AS OF [MAY 31], 2024 *{update to come}*
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Government Securities	$ 20,747
U. S. Sponsored Agency Issues	392,993
Supranationals	11,297
Medium term corporate notes	109,613
Municipal obligations	53,970
California state bonds	9,825
Other state bonds	34,544
Commercial paper	--
Certificates of deposit	33,524
Money market funds	27,989
Total	$694,501

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 [May 31], 2024, the Power System had approximately $1.52 billion of unrestricted cash and approximately $1.03 billion of restricted cash on deposit with the City. *{update to come}* 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. *{update to come}*

CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, [2023] *{update to come}*
(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 as of June 30, 2024 and 2023, 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. In June 2024, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2024-25 of 1.48% 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 start a water rate review in the first six months of calendar year 2025, but is still reviewing the need and proposed schedule for the next power rate action with the Chief Executive Officer. Department staff expects the power rate action to start after the completion of the water rate action.

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.

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 before the end of calendar year 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. The OATT has been and may be amended or updated from time-to-time. 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 was increased to 2.0% of Power System sales beginning in Fiscal Year 2020-21. Since that time, a new accrual approach has been adopted for the allowance for doubtful accounts, which uses a three-year write-off average rate of Power System sales, starting in Fiscal Year 2023-24 (0.5%). As of August 31, 2024, the Power System's allowance for doubtful accounts was $314.6 million and accounts receivable were $1.37 billion (including utility user's tax). Of these amounts, $768.4 million (56.18% of total receivables) were 120 days or more past the payment due date. As of August 31, 2023, the Power System's allowance for doubtful accounts was $280.4 million and accounts receivable were $1.16 billion (including utility user's tax). Of these amounts, $626.0 million (54.15% 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 began to resume service disconnections for certain residential customers in June 2024). 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. In September 2021, the Department submitted a funding request of approximately $203 million for residential arrearages and approximately $109 million for commercial arrearages. The Department received $202.8 million of 2021 CAPP 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 ("2022 CAPP"), which dedicated approximately $1.2 billion to address Californian's energy debts. In October 2022, the Department submitted a funding request of approximately $76.6 million for residential arrearages. The Department received the requested 2022 CAPP 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 10,886 megawatts ("MW") and net dependable capacity of 8,081 MW as of August 31, 2024, and properties with a net book value of approximately $14.2 billion as of [May 31], 2024. *{update to come}*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 adopted a goal in August of 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 3,434 gigawatt hours ("GWhs") from 2023 to 2035, surpassing the 1,802 GWhs of projected savings reflected in the LA100 Study. For the operating statistics of the Power System, see "OPERATING AND FINANCIAL INFORMATION – Summary of Operations."

The Department estimated that the Power System's capacity (as of August 31, 2024) 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 August 31, 2024.
[(2)] Energy percentage is based on the Department's calendar year 2022 fuel mix submission as part of the 2022 Annual Power Content Label to the California Energy Commission in September 2023. The Department's 2023 Annual Power Content Label will be available in January 2025.
[(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 August 31, 2024.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of August 31, 2024, 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	3,191
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**	**4,753**
Less: Payable to the California Department of Water Resources	–	–	(120)[5]	(48)[5]
Total	**72**	**200**	**4,955**	**4,705**

Source: Department of Water and Power of the City of Los Angeles.

(1) Based on 2023-24 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 3,191 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 1,507 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 528 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. There are approximately 3,200 individual plaintiffs represented by various counsel. The final number of individual plaintiffs is expected to be approximately 1,300 after plaintiffs who have not participated in discovery are dismissed. The court is holding regular status conferences to determine the future schedule of the pending matters. All pending cases have been deemed related by the court and are assigned to the same judge in the Los Angeles Superior Court. No final status conference or trial date have been set.

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 422 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 734 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 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. 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, including increased use of energy storage, retrofitting existing gas units that currently use once-through-cooling with alternative cooling designs such as using wet cooling towers, and introducing hydrogen capable gas generating units to replace once-through-cooling units, 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 – *Strategic Long-Term Resource Plan*."

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 35 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 29 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 August 31, 2024, 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.

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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)	1,175
Natural Gas	1	578	483
Large Hydro	1	496(2)	270(2)
Nuclear	1	387(3)	380
Renewables/Distributed Generation	87,508(4)	3,268	1,068(5)
Total	**87,512**	**5,931**	**3,376**

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 2023-24, the IPP operated at a plant net capacity factor of 26.22% and provided approximately 4.1 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes approximately 2.4 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 (the "IPP Agreement for Sale of Renewal Excess Power") 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 have recalled 1.05% of the capacity of IPP (equal to 19 MW) from the Department for the winter season which started September 2024 and will end March 2025. 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 IPP Agreement for Sale of Renewal Excess Power which will take effect on the same day as the IPP 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 IPP 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 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, 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 announced the closure of the mine in November 2023. 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, production continues to be 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. The coal is transported primarily 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.

IPP generally maintains a minimum of 60 days of coal in inventory in the event of a coal supply disruption. At the end of August 2024, IPP maintained 223 days of coal in inventory.

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 and potential implications of certain recently enacted Utah legislation with respect thereto, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Air Quality – Mercury*," "*– Coal Combustion Residuals*," and "*– Utah Senate Bill 161*."

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 2023 annual funding status report which is based on a 2019 study of decommissioning costs, 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 73% funded and that its share of decommissioning costs through SCPPA was 84% funded. The Department's direct share of costs is $204.9 million and SCPPA's share is $222.0 million, of which the Department's portion is $148.7 million or 67%. Under the current funding plan, the Department estimates its share of the decommissioning costs relating to the Department's direct ownership interest in PVNGS will be fully funded by accumulated interest earnings and additional contributions 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 August 31, 2024, 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 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. See also "–Renewable Power Initiatives – *L.A.'s Green New Deal*" and – *Strategic Long-Term Resource Plan*."

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. The Department's Annual Power Content Label for 2023 will be available in January 2025.

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.

Large Scale Solar Energy. 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 LLC (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 LLC. 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 LLC. 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 was developed by Arevon Energy, Inc., with commercial operation occurring in November 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 Arevon Energy, Inc., 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*."

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 generating capacity from the Heber-1 Project is expected to be 52 MW. The Department's share is 78.0% (40.56 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 338 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). The maximum annual energy received by the Power System from the project is expected to be approximately 1,620 GWhs. The power sales agreement with SCPPA expires in December 2043.

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 110.6 MW comprised of 4 MW of solar photovoltaic generation in the Owens Valley and 4 MW of renewable landfill gas generation, and 102.6 MW of photovoltaic generation installed within the Department's in-basin 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 the pricing of a portion of their electric bills based upon the costs and benefits of 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; (vii) the FiT Plus program, which facilitates the installation of energy storage with existing and new FiT photovoltaic projects; and (viii) the Self Generation Incentive Program ("SGIP"), which the Department has recently been authorized by the CPUC to administer for its service territory, and which initially includes approximately $36.0 million in funding for deploying solar and energy storage in low-income households. In total, approximately 659.58 MW of customer-owned net energy metered photovoltaic solar projects have been installed in the Department's in-basin service territory as of September 2024.

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 26.79 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 7.79 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'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.

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 was commissioned in November 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. There were approximately slightly more than 9,100 Department customers subscribed to the Green Power Program as of August 2024.

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 repowering 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.

Strategic Long-Term Resource Plan. 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, which establishes the State policy goal of achieving the supply of all retail sales of electricity in California from renewable and carbon-free resources by 2045 (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, and includes a general assessment of the revenue requirements and rate impacts (preliminary, averages) to support a recommended resource plan through 2035 and 2045. 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. In June 2024, the OPA issued a review of the 2022 Strategic Long-Term Resource Plan, focused on the potential rate impacts of the plan. In its review, the OPA noted that the estimated average annual impact on rates for 2022 through 2035 of the three cases modeled in the 2022 Strategic Long-Term Resource Plan to achieve carbon-free energy by 2035 ranged from approximately 7.7% to 8.3%, as compared to approximately 4.8% for the SB 100 comparison case (roughly 90% clean energy by 2045). 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 3,434 GWhs from 2023 to 2035, surpassing the 1,802 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 started offering electrification incentives for all electric commercial cooking equipment and appliances.

Custom Performance Program/Business Offerings for Sustainable Solutions. As initially established, the Custom Performance Program (the "CPP") provided 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, retro-commissioning, chiller efficiency, and/or other innovative energy savings strategies.

Beginning July 1, 2024, the CPP was rebranded as the Business Offerings for Sustainable Solutions ("BOSS") Program. The BOSS Program continues to fast-track smaller, less energy-intensive projects through its "Custom Express" service, which offers energy savings projections to expedite application processing and faster payments to customers. Additionally, the Custom Calculated service provides in-depth analyses to custom calculate the energy savings of individual efficiency projects. Since 2007, the CPP/BOSS Program has achieved over 613 GWhs of energy savings and introduced electrification incentives for space and 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 better meet their lighting needs, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 821 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 524 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 initiative targeting customers who qualify under the Department's Low-Income or Senior Citizen/Disability Lifeline Rates, as well as multi-residential and non-profit customers. The program has expanded to include multi-family and mobile home communities, civic, community, faith-based organizations, and educational institutions. Currently, the REP is suspended while the program seeks a new third-party contractor to administer the program and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Since 2007, REP has achieved 106 GWhs of energy savings.

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 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.

As the Department ramps up its technology assessment efforts in the Emerging Technologies program, it has partnered with the NREL to develop a technology prioritization tool. The tool prioritizes 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 for 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 August 2024, the Department has spent approximately $1.8 billion on its energy efficiency programs, and these programs are estimated to have reduced long-term peak period demand and consumption by approximately 980 MW and resulted in approximately 5,816 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers saved approximately 277 GWh incrementally for Fiscal Year 2023-24, falling short of energy savings targets by 109 GWh. The Department spent approximately $125 million on energy efficiency programs for Fiscal Year 2023-24 of its approximately projected $183 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 better manage their use of electricity. 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 41 billion equivalent cubic feet of natural gas during Fiscal Year 2023-24. In addition, the Department's fossil fuel requirements for the Apex Power Project were 17 billion equivalent cubic feet of natural gas during Fiscal Year 2023-24. 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. *{update to come}* 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 August 31, 2024, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2029-30 with an aggregate notional amount of approximately 75.3 million MMBtu. These financial hedges cover up to approximately 42% of the Department's natural gas requirements based on the latest budget for the Fiscal Years through 2029-30. Tables describing the notional amount for specified Fiscal Years and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with the Department's financial natural gas hedges as of June 30, 2024 and 2023, 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 August 31, 2024, approximately 42% and 31% of the Department's projected natural gas needs have been hedged for Fiscal Year 2025-26 and Fiscal Year 2026-27, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2029-30, approximately 3% 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 was 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. In August 2023, the CPUC approved an increase in the allowable storage at the facility to 68.6 BCF. The CPUC proceeding regarding whether to permanently close that storage facility is expected to conclude with a proposed decision in December 2024. 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 2023 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 373 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 on various dates 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 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. 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. Under the Agreement for Sale of Renewal Excess Power, which will take effect in June 2027, the Department will be provided with firm transmission rights to approximately 50% of the total capacity on each of the sections of the NTS. The Department can have up to a maximum NTS share allocation of 100% of the total NTS capacity depending on the generation deemed excess by the Utah municipalities and cooperatives that have access to such power post-2027. See "– Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

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 below, for Fiscal Year 2024-25 through Fiscal Year 2028-29, the Department expects to invest approximately $14.3 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2024
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$ 2,070
IT Infrastructure*	512
Energy Efficiency	1,066
Power System Reliability Program	5,918
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	2,641
Power System Resource Plan	5
Shared Services: Facilities, Customer Services, Fleet	2,059
Total Power System Capital Improvements	$14,269

Source: Department of Water and Power of the City of Los Angeles.

* For planning purposes, the power financial plan includes a proposed IT Cost Adjustment Factor (ITCAF) with an effective date of July 1, 2025. 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.

Note: Total may not equal sum of parts due to rounding.

The table below indicates, for Fiscal Year 2024-25 through Fiscal Year 2028-29, 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)]
2025	$1,270	$1,126	$2,396
2026	969	1,661	2,630
2027	1,382	2,005	3,387
2028	992	2,018	3,011
2029	1,071	1,774	2,845
	$5,685	$8,584	$14,269

Source: Department of Water and Power of the City of Los Angeles.

(1) Net of reimbursements to the Department.

Note: Totals 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 5,220 customers are served. As of [June 30, 2024], [33]% of the Power System's total energy sales (measured in MWhs) were to residential customers, [62]% to commercial and industrial customers and the remaining [5]% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately [35]%, [61]%, and [4]% of total revenue, respectively. *{to be updated}*

Summary of Operations

The table below provides certain operating information with respect to the Power System.

POWER SYSTEM
SELECTED OPERATING INFORMATION
(Unaudited)

	Fiscal Year Ended June 30				
Operating Statistics	**2024**	**2023**	**2022**	**2021**	**2020**
Net Energy Load[1]		23,859	23,997	23,797	24,096
Net Hourly Peak Demand (MW)		6,216	4,911	6,106	5,637
Annual Load Factor (%)		43.81	55.79	44.49	48.66
Electric Energy Generation, Purchases and Interchanges[1]					
Generation[2][3]		17,172	17,194	17,281	17,947
Purchases[2]		9,148	9,440	8,988	7,295
Miscellaneous Energy Receipts[1]		–	–	705	470
Total Energy[2]		26,320	26,634	26,974	25,712
Less:					
Miscellaneous Energy Deliveries[1][4]		426	511	–	–
Losses and System Uses[1]		2,386	2,595	4,479	3,879
On-System Sales[2]		23,508	23,528	22,495	21,833
Sales of Energy[1]					
Residential		7,736	7,383	7,707	7,218
Commercial and Industrial		13,959	14,092	13,220	14,030
All Other		1,722	1,891	2,087	1,050
Total		23,417	23,366	23,014	22,298
Number of Customers – (Average, in thousands):					
Residential		1,440	1,430	1,414	1,405
Commercial and Industrial		128	128	126	126
All Other		7	7	7	7
Total		1,575	1,565	1,547	1,538

Source: Department of Water and Power of the City of Los Angeles.
(1) Thousands of MWhs.
(2) 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.
(3) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.
(4) 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)

	Fiscal Year Ended June 30[1]				
	2024	**2023**	**2022**	**2021**	**2020**
Operating Revenues					
Residential		$1,717,646	$1,637,120	$1,614,033	$1,360,648
Commercial and Industrial		2,857,601	2,784,691	2,492,138	2,372,533
Sales for resale[2]		326,347	230,160	186,706	61,455
Other[3]		56,945	(58,211)	(24,399)	12,655
Total Operating Revenues		$4,958,539	$4,593,760	$4,268,478	$3,807,291
Average Revenue per kWh Sold[4]					
Residential		0.222	0.222	0.209	0.189
Commercial and Industrial		0.205	0.198	0.189	0.169
Average Annual Residential Usage[5]		5	5	5	5
Operating income		$ 742,176	$ 800,988	$ 744,139	$ 363,981
As % of revenues		15.0%	17.4%	17.4%	9.6%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[6]		$ 833,815	$ 532,290	$ 633,942	$ 320,065
Adjusted Change in Net Position, including Power Transfer and accounting change[6]		$ 601,772	$ 307,275	$ 415,587	$ 90,152

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) Includes sales of power and transmission services to other utilities.

(3) Net of Uncollectible Accounts.

(4) 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.

(5) MWh use per residential customer.

(6) "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)

	Fiscal Year Ended June 30[1]				
	2024	**2023**	**2022**	**2021**	**2020**
Operating Revenues					
Sales of Electric Energy:					
Residential		$1,717,646	$1,637,120	$1,614,033	$1,360,648
Commercial and industrial		2,857,601	2,784,691	2,492,138	2,372,533
Sales for resale		326,347	230,160	186,706	61,455
Other[3]		56,945	(58,211)	(24,399)	12,655
Total Operating Revenues		$4,958,539	$4,593,760	$4,268,478	$3,807,291
Operating Expenses					
Production:					
Fuel for Generation		$ 435,524	$ 327,813	$ 228,697	$ 207,043
Purchased Power		1,448,692	1,309,505	1,301,394	1,242,068
Energy Cost		1,884,216	1,637,318	1,530,091	1,449,111
Maintenance and Other Operating Expenses		1,570,429	1,430,993	1,323,158	1,364,303
Adjusted Operating Expenses[4][6]		$3,454,645	$3,068,311	$2,853,249	$2,813,414
Adjusted Operating Income[4][6]		$1,503,894	$1,525,449	$1,415,229	$ 993,877
Other non-operating income and expenses, net		413,808	1,482	145,303	268,502
Contributions in aid of construction		76,942	100,865	103,459	57,692
Adjusted Change in Net Position[5][6]		$1,994,644	$1,627,796	$1,663,991	$1,320,071
Debt Service					
Adjusted Interest[6][7]		517,818	479,482	459,413	454,074
Principal		190,315	187,683	179,405	171,925
Total debt service		$ 708,133	$ 667,165	$ 638,818	$ 625,999
Debt Service Coverage Ratio		2.82	2.44	2.60	2.11
Depreciation, amortization and accretion		$ 761,718	$ 724,461	$ 671,090	$ 629,896
Transfers to the Reserve Fund of the City		$ 232,043	$ 225,015	$ 218,355	$ 229,913

Source: Department of Water and Power of the City of Los Angeles.
(1) Derived from the Power System Financial Statements.
(2) Net of Uncollectible Accounts.
(3) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.
(4) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.
(5) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements.
(6) Interest expense excluding amortization of debt premium.

Indebtedness

As of December 1, 2024, approximately $11.52 billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $10.18 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 $8.6 billion of debt through June 30, 2029 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 of approximately $1.2 million annually for the currently outstanding federally subsidized direct-pay bonds 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 $19.5 million annually.

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 December 1, 2024, the Department had no borrowings outstanding under the Wells RCA payable from either the Power Revenue Fund or 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) as of June 30, 2024 and 2023, see "Note (9)(d) Variable Rate Bonds" of the Department's Power System Financial Statements.

In addition, as of December 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 $3.01 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 December 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 a 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 December 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 December 1, 2024
(Dollars in Millions)
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt(6)
Intermountain Power Agency			
IPP	$ 113(1)	48.62%(2)	$ 55(1)
IPP (Renewal Project)	1,695	71.44	1,211
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	14	100.00(3)	14
Mead-Phoenix Transmission Project	11	100.00(3)	11
Linden Wind Energy Project	75	100.00(4)	75
Milford Wind Corridor Phase I Project	65	92.50(5)	60
Milford Wind Corridor Phase II Project	59	100.00(4)	59
Southern Transmission System (STS)	101	59.50(5)	60
STS (Renewal Project)	1,238	90.50(5)	1,120
Windy Point Project	149	100.00(4)	149
Apex Power Project	193	100.00(5)	193
Total	$3,711		$3,007

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 Appendix A – "FINANCIAL STATEMENTS" for additional information.

Note: Totals may not equal sum of parts due to rounding.

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 Series E 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 current 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. However, as described below, CARB has initiated the process for further updates to the Cap-and-Trade Regulations. The scope of the potential amendments to be considered by CARB include, among other things, the removal of significant allowances from the annual allowance budget commencing in 2026 and requirements for POUs to consign all their allocated allowances to auction similar to investor-owned utilities. The Department could be adversely affected in the future if the GHG 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 from existing operations in meeting retail load obligations.

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 ("EDAM") 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. Informal rulemaking activity, including a series of public workshops to discuss potential amendments to the Cap-and-Trade Regulations, commenced in June 2023. The potential amendments of interest to the Department include: revisions (reductions) to the 2026 through 2030 electric utility allowance allocation based on the most recent forecasts and RPS target; requirements for POUs to consign all their allocated allowances to auction similar to investor-owned utilities; the phasing out of the RPS adjustment credit for firmed/shaped electricity imports; how reducing the cap-and-trade program allowance budget (the cap) would increase allowance prices; adding the new EDAM to the outstanding emissions leakage calculation; and providing benefits to low-income customers and disadvantaged communities. In April 2024, CARB posted the Standardized Regulatory Impact Assessment ("SRIA") for the Cap-and-Trade Regulations. The SRIA is an initial economic evaluation of potential changes to the cap-and-trade program and is one of the steps CARB must take prior to updating the Cap-and-Trade Regulations. In July 2024, CARB held a workshop to discuss potential revisions to the cap-and-trade program emission allowance budget to achieve the more ambitious emission reduction targets of 48% by 2030 and 85% by 2045, including the removal of 180 to 265 million allowances in aggregate from budget years 2026 through 2030. In October 2024, CARB posted another market notice to inform market participants about the timing and topics for the upcoming amendments to the Cap-and-Trade Regulations. The notice states that CARB aims to make the formal rulemaking proposal available for public comment before the end of 2024. Assuming that the formal rule amendments package is posted in late 2024 or early 2025, the amendments are anticipated to take effect prior to the end of 2025.

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 and March 2019, the CEC adopted the "Toward A Clean Energy Future, 2018 Integrated Energy Policy Report Update" (the "2018 IEPR Update"). The 2018 IEPR Update is composed of two volumes. The first volume (August 2018) is a high-level summary of the energy policies the State has implemented. 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 (March 2019) 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 2024, 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's 2023 wildfire mitigation plan was a comprehensive update, meeting the requirements of AB 1054. On December 4, 2023, the CWSAB published its guidance advisory opinion for the POU-submitted 2023 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 has actively participated in the CWSAB's meetings to discuss updates to POU wildfire mitigation plans. The Department was required to submit its 2024 annual update to the Department's wildfire mitigation plan to the CWSAB by July 1, 2024. The Department continues to submit its wildfire mitigation plan to the CWSAB on an annual basis, with the last submittal occurring on June 27, 2024, in satisfaction of the requirement. The Department is required to submit its next annual update to the Department's wildfire mitigation plan by July 1, 2025.

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 SCAQMD Rule 1135 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 SCAQMD Rule 1135 NOx limit of 2.0 ppm for combined cycle gas turbines, the combustors of the combined cycle gas turbines at the Harbor Generating Station were upgraded with dry low NOx combustors. The upgrade of the Harbor Generating Station's combined cycle gas turbine combustors began construction in October 2023 and completed commissioning in April 2024. The Harbor Generating Station's combined cycle unit is currently operational and is in compliance with the Rule 1135 NOx emission limit since its return to service in April 2024. 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. As originally proposed, this 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 included 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 would be 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. As proposed, the 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 would be based on emission control methods that can be installed at the plants, including technologies such as carbon capture and sequestration/storage ("CCS"), 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 Department participated in the rulemaking process.

In February 2024, the EPA announced that it would remove the elements that would have applied to existing natural gas-fired power plants from the final version of the rule. Instead, the EPA stated that it will commence a new rulemaking process that will apply to existing natural gas-fired plants and regulate additional pollutants.

On April 25, 2024, the EPA released the final rules for existing coal-fired and new natural gas-fired power plants that limits CO_2 emissions from existing coal-fired plants and new gas-fired combustion-turbine plants based on EPA's emissions guidelines. Multiple legal challenges were filed shortly thereafter including a stay request. In July 2024, the D.C. Circuit Court denied the stay request, but indicated they would expedite hearing the merits of the case. On October16, 2024, the Supreme Court issued an order denying requests to stay the rule, indicating that a stay was not necessary since compliance is not required until 2030 or 2032, by which time the D.C. Circuit is likely to have issued a decision on the merits of the case. Litigation over the rule continues in the D.C. Circuit where the briefing schedule has been expedited so that the case will be argued within the 2024 term. Briefing and oral arguments are scheduled to occur before the end of 2024. A decision is expected in the spring of 2025.

Under the final rule, for new baseload combustion turbines, the emission guidelines are based on BSER, which the EPA determined to be CCS with 90% capture of CO_2. Under the final rule, new combustion turbines with a capacity factor of 40% or more are baseload turbines and are subject to a CO_2 emission standard of 100 lb. CO_2/MWh, starting on January 1, 2032. Prior to 2032, the emission standard is between 800 to 900 lb. CO_2/MWh depending on the size of the unit. Intermediate turbines, which have a capacity factor between 20% and 40% will be subject to a standard of 1,170 lb. CO_2/MWh, which is based on efficient operation of simple cycle turbines. Low load turbines, which have a capacity factor of less than 20% are subject to a standard of 120-160 lb. CO_2/MMBtu, based on use of low-emitting fuel (e.g., natural gas and certain fuel oils). The standards under the final rule are technology-neutral, therefore allowing the affected sources to comply with the emission standard through hydrogen co-firing.

For existing oil and natural gas-fired steam electric generating units, standards are based on routine operation and maintenance with different levels of stringency based on the capacity factor. The emission standard for natural gas-fired units with a capacity factor of less than 8% is 130 lb. CO_2/MMBtu. Intermediate units with capacity factor of 8 to 45% are subject to an emission standard of 1,600 lb. CO_2/MWh while baseload units with capacity factor of 45% or more must comply with an emission standard of 1,400 lb. CO_2/MWh.

Coal-fired generating units that plan to cease operations prior to January 2032 are exempt from the final rule. Therefore, IPP's coal units will not be subject to the emission reduction obligations under the final rule. IPP's new natural gas units, which will be considered an existing natural gas-fired power plant, will also not be subject to this final rule but will be subject to the new rule being developed for existing gas-fired combustion turbines.

To help the EPA develop standards for reducing GHG emissions as well as criteria pollutant emissions from existing gas-fired combustion turbines in the power sector, the EPA opened a non-regulatory docket on March 26, 2024. The non-regulatory docket included key framing questions on factors to consider when regulating emissions from existing gas turbines. The EPA requested stakeholders to provide responses to these questions and accepted comments from stakeholders through May 28, 2024. The Department submitted comments on the docket, asking the EPA to consider technical feasibility, cost-effectiveness, reliability, and the need for compliance flexibilities when developing the rule for existing gas units. In response to continued outreach by the EPA to solicit input on key areas of the upcoming rulemaking, the Department submitted a comment letter on October 15, 2024. The Department's comment letter reiterated the importance of grid reliability, compliance flexibilities, subcategorization, and relying on technologies that are viable for existing combustion units. A proposed rule is expected by early 2025.

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 ("NESHAPs"): 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.

On April 25, 2024, the EPA released the final NESHAPs rule (also referred to as the MATs rule) which finalizes the proposed change to the fPM emission standard from 0.03 lb./MMBtu to 0.01 lb./MMBtu. The final rule also requires that existing coal and oil-fired units utilize CEMS to demonstrate compliance with the fPM emission standard. The compliance date for affected coal-fired sources to comply with the revised fPM limit is three years after the effective date of the final rule. With IPP replacing the coal units with natural gas-fired units by 2025, IPP will not be subject to the more stringent requirements under the final MATS rule.

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 submitted a request to the EPA demonstrating that they meet the alternate closure procedures as described in the regulations. The EPA confirmed that IPP's demonstration was complete on January 11, 2022; however, as of October 2024, the EPA had not yet made a substantive determination on IPP's demonstration submission. Nonetheless, the April 2021 cease operation of the impoundments is tolled under the regulations because the IPP submitted a timely demonstration.

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. On April 25, 2024, the EPA released a final rule on the proposed closure option for units being closed by removal of CCR. The EPA is still considering other provisions from the proposed revisions that were not addressed in the final rule and may be addressed in a subsequent action.

Utah Senate Bill 161. The Utah Legislature enacted Utah Senate Bill 161 ("Utah S.B. 161") in its 2024 General Session, which became effective on May 1, 2024. The reported purpose of Utah S.B. 161 was to induce IPA to amend IPA's environmental permits to provide for the operation of at least one of the IPP coal-fired units after July 1, 2025, the date by which IPA has committed to cease operation of the IPP coal units permanently. Utah S.B. 161 also required IPA to grant an option to the State of Utah for the purchase of at least one of the IPP coal-fired units with such option to be effective for two years starting on July 2, 2025. Following the enactment of Utah S.B. 161, the governor of Utah called a special session of the Utah Legislature resulting in the enactment of Utah House Bill 3004 ("Utah H.B. 3004"), which became effective on June 21, 2024. Utah H.B. 3004 repealed the provisions of Utah S.B. 161 relating to IPA amending its environmental permits. IPA continues, however, to be obligated to provide the purchase option to the State with respect to one of the IPP coal-fired units. Utah H.B. 3004 also directs a state agency, the Decommissioned Asset Disposition Authority (the "Utah Disposition Authority"), to submit an application to amend IPA's air permit to allow for a coal unit to operate after July 1, 2025. Utah H.B. 3004 also directs environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority has also been directed to determine the regulatory and commercial feasibility of operating an IPP coal unit after July 1, 2025, and to conduct a process for soliciting bids from qualified purchasers for the coal unit.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation and moved things in the right direction. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments.

The Department cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

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.

FERC Order 1920. On May 13, 2024, FERC issued Order No. 1920 ("Order 1920") to reform the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. Order 1920, among other things, requires public utility (jurisdictional) transmission providers to conduct and periodically update long-term regional transmission planning to anticipate future needs, consider a broad set of benefits when planning new facilities, identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, propose methods of cost allocation to pay for selected long-term regional transmission facilities, and increase transparency regarding local transmission planning information. Order 1920 expands the role of states throughout the process of planning, selecting and determining how to pay for new transmission facilities. Order 1920 reflects 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. As a municipal utility actively participating in the WestConnect regional transmission planning process, the Department has expressed its support of long-term regional transmission planning and its intent, in collaboration with WestConnect, to adhere to the principles of Order 1920. The Department is evaluating the implications of Order 1920 with respect to the transmission planning processes of the Power System.

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 were 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. Such initiatives may purport to be retroactive.

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, a significant number of individual plaintiff cases were dismissed, leaving approximately 300 individual plaintiff cases. The dismissals significantly reduce the Department’s financial exposure for the wildfire.

Both the insurance subrogation plaintiffs and almost all of the individual plaintiffs have settled with Edison. The remaining individual plaintiffs who have not settled with Edison have entered into a stipulated judgment with Edison whereby Edison accepts a judgment against it without admitting liability. A damages trial is scheduled for June 2, 2025. It appears that Edison will eventually pursue its indemnity cross-complaint against the Department.

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 total financial exposure of the Getty Wildfire is likely set at approximately $81.3 million, which represents the estimated total for anticipated settlement agreements with all plaintiffs. The Department is responsible for $3 million of this amount; the rest is covered by insurance. On or about October 16, 2023, the Department settled with the insurance subrogation plaintiffs for $36,355,272, which is finalized. The Department is in the process of finalizing a settlement with the individual plaintiff group. It is anticipated that the amount of this settlement will be well 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. 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.

THE CITY OF ANAHEIM

The following is information concerning the City of Anaheim ("Anaheim" or, in this section, the "City"), its Public Utilities Department (the "Anaheim Public Utilities Department" or "Department") and such Department's electric utility (the "Anaheim Electric System" or the "Electric System"), prepared by Anaheim for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Anaheim Electric System. A copy of the most recent audited financial statements of the Anaheim Electric Utility Fund ("Anaheim's Financial Statements") may be obtained from the Assistant General Manager–Finance & Energy Resources, Anaheim Public Utilities Department, 201 South Anaheim Boulevard, Suite 902, Anaheim, California 92805, and is also available on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at http://emma.msrb org. Anaheim's Financial Statements are incorporated herein by this reference. However, other information presented on such website or referenced therein other than Anaheim's Financial Statements is not part of this Official Statement and is not by reference to such website incorporated herein.

Organization

The City of Anaheim (the "City" or "Anaheim") is a chartered city of the State of California. Under the provisions of the California Constitution, the Charter of the City of Anaheim (the "Charter") and Title 10 of the Municipal Code of the City, the City owns and operates both an electric system (the "Electric System") and a water system (the "Water System") for the citizens of the City. The Public Utilities Department of the City ("APU," the "Department" or the "Public Utilities Department") exercises jurisdiction over both the Electric System and the Water System and is under the supervision of the Public Utilities General Manager (the "General Manager"). The General Manager supervises the design, construction, maintenance and operation of both the Electric System and the Water System. The Finance Director/City Treasurer oversees the accounting and administration of the financial affairs of the City. The Anaheim City Council (the "City Council") appoints the City Manager, who provides direction to the General Manager and Finance Director/City Treasurer.

The Electric System and the Water System provide services to virtually all residential, commercial, and industrial customers within City limits. The funds and accounts of the Electric System and the Water System are held separately, and the funds and accounts of one system are not pledged to the other system's obligations.

Management of Anaheim Public Utilities

The following are biographical summaries of the executive management team of Anaheim Public Utilities with responsibility for the Electric System:

Dukku Lee, Public Utilities General Manager, has served Anaheim Public Utilities since November 1999 and was appointed as its General Manager in November 2013. He has full management responsibility to plan, direct, and manage APU's day-to-day activities and operations. Mr. Lee began his career in the utility industry in 1993. Prior to his appointment as General Manager, Mr. Lee held the position of Assistant General Manager–Electric Services with responsibility for managing the engineering, construction, operation and maintenance of the utility generation, transmission, and distribution system. Mr. Lee previously worked for Southern California Edison ("Edison") and Paragon Consulting Services. Mr. Lee holds a Bachelor of Science degree in Electrical Engineering from California State Polytechnic University, Pomona and a Master of Science degree in Engineering Management from California State University, Long Beach and is a registered Professional Engineer in the State of California. Mr. Lee is on the Board of Directors of the Southern California Public Power Authority ("SCPPA") and the Board of Governors of the California Municipal Utilities Association ("CMUA").

Brian Beelner, Assistant General Manager–Finance & Energy Resources, has served Anaheim Public Utilities since 2005. He is responsible for multiple aspects of APU including accounting, budget development, financial planning, rate design, long-term forecasting, debt administration, warehousing and supply chain, power supply, and information technology. Prior to joining the City, Mr. Beelner worked for Gursey, Schneider & Co., LLP as a municipal utility accounting and finance consultant. Mr. Beelner graduated from the University of California, Riverside with a Bachelor of Arts degree in Business Economics and currently holds an active Certified Public Accountant license in the State of California. He is a member of the SCPPA Finance Committee and an alternate member of SCPPA's Board of Directors, a member of the Coordinating Committee for the Intermountain Power Project ("IPP"), and a member of the San Onofre Nuclear Generating Station Decommissioning Executive Committee.

Janet Lonneker, Assistant General Manager-Electric Services, joined Anaheim Public Utilities in May 2014, and is responsible for directing, managing, supervising, and coordinating the activities and operations of the Electric Services Division, including electrical engineering, electric operations, system planning, substations, and power generation. Ms. Lonneker has over 25 years of electric utility industry experience, most recently before joining Anaheim as a Customer Solutions Manager for San Diego Gas and Electric ("SDG&E") where she worked within the Smart Grid Division. Prior to her employment at SDG&E, she was General Manager for the City of Forest Grove's Department of Light and Power for six years, where she was responsible for leadership, management, and oversight of all divisions of the utility. Ms. Lonneker holds a Bachelor of Science degree and a Master of Science degree in Electrical Engineering from the University of the Pacific and the University of Southern California, respectively.

Janis G. Lehman, Assistant General Manager-Administration & Risk Services, has been with Anaheim Public Utilities since 1990. She currently leads the Administration and Risk Services Division which is responsible for enterprise risk management, environmental and regulatory compliance, safety services, legislative and regulatory affairs, and customer service including credit collections and billing. She has experience in all key aspects of the water and electric utility industry. She started her career at APU managing transmission line and power generation projects, as well as developing water programs. Her career path has included working as a hazardous materials design specialist for water and soil projects, a first responder on hazardous materials emergency response teams, and as an engineer at Bechtel Engineering before coming to APU. She has taught several courses on regulatory compliance through California State University. Ms. Lehman currently serves as an alternate on the CMUA Board of Governors. She is a member and past chair of the CMUA Legislative Committee and the Regulatory committee. She is also a member and past chair of the SCPPA Risk Management Committee, a member of the Credit Working Group of the California Independent System Operator Corporation ("CAISO"), and has testified as an expert witness at the California Public Utilities Commission ("CPUC"). Ms. Lehman has a Bachelor of Science degree in Geophysics from University of California, Riverside, and a Master of Business Administration degree from the University of Southern California.

Public Utilities Board

The City Council, by Ordinance No. 3557 approved July 6, 1976, established a Public Utilities Board (the "Public Utilities Board" or the "Board") with the power and duty to make recommendations to the City Council for consideration by the City Council in its determinations concerning (i) the operation and conduct of the Water System and the Electric System, (ii) the establishment of rules and regulations and rates for the operation of the Water System and the Electric System, (iii) the duties and qualifications of the General Manager and other employees of the Department, (iv) the acquisition, construction, improvement, extension, enlargement, diminution or curtailment of all or any part of the Water System and the Electric System, (v) the annual budget of the Department, and (vi) financing, including the issuance of bonds for the Water System and the Electric System. On June 3, 2014, Anaheim voters approved Measure C which, among other things, adds Section 909 to the Charter specifying the powers and duties of the seven-member Public Utilities Board. The Board may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the Charter.

The Board consists of seven members, none of whom may hold any paid office or employment in the City government. The members of the Board are appointed by the City Council and may be removed by a majority vote of the City Council. Board members serve four-year overlapping terms and are limited to serving two consecutive four-year terms.

The present members of the Board and their terms of appointment are:

John Seymour, Chairperson, term expires December 31, 2026. Mr. Seymour joined the Board in April 2017, and was reappointed in January 2023. He is a retired telecommunications executive with a Bachelor's degree from Whittier College in Economics and Business Administration with an emphasis in Accounting. Mr. Seymour previously served on the City's Planning Commission (2010-2017), and is a former member and chair of the Public Utilities Board's Underground Conversion Subcommittee. He served on the board for the Anaheim Regional Medical Center for over twenty years, and served as a board member for Memorial Health Services.

Abdulmageed Abdulrahman, ***Vice Chairperson, term expires December 31, 2024***. Mr. Abdulrahman joined the Board in July 2015, and was reappointed in January 2021. He holds a Bachelor's degree in Mechanical Engineering from Khartoum University, Sudan and a Master's degree in Industrial Management from the University of Central Missouri. He is a licensed Professional Engineer, works as an associate oil and gas engineer with the State of California, and has served on the City's Budget, Investment & Technology Commission (2013-2015), and the City's Ad Hoc Housing Element Committee (2013-2014). Mr. Abdulrahman is also a member of the American Society of Mechanical Engineers and the Society of Petroleum Engineers. He is currently serving as the chairperson of the Public Utilities Board's Underground Conversion Subcommittee.

Anh Pham, M.Ed., term expires December 31, ***2025***. Mr. Pham joined the board in February 2022. He is a policy analyst for the University of California, Irvine and prior to that spent a decade working for the University of California, Riverside. He earned a Bachelor of Arts degree in public policy as well as a Master of Education in Higher Education Administration and Policy from University of California, Riverside. Mr. Pham's community involvement includes roles with organizations such as AnaheI'M First, UC Riverside Orange County Alumni Association, West Anaheim Organization and the West Anaheim Neighborhood Development Council.

Albert McMenamin, term expires December 31, ***2026***. Mr. McMenamin joined the Board in January 2023. He began his career with the City. During his 36-year career, he worked in the water services division and held the positions of Equipment Operator, Maintenance Pipefitter and Senior Water Utility Inspector. Mr. McMenamin has also worked part time with the Los Angeles Angels since 2001.

Talab Ibrahim, term expires December 31, ***2024***. Mr. Ibrahim joined the Board in February 2023. He attended California State University, Fullerton where he earned his Bachelor of Science degree in Civil Engineering. Throughout his college career he joined the American Society of Civil Engineers and Institute of Transportation Engineers. Additionally, he co-founded and served as president of the Palestinian American student body at California State University, Fullerton, volunteering, serving locals and collaborating with other non-profit organizations. His involvement continued through the AnaheI'M First community meetings and volunteering at events at local mosques. Currently, he manages a family business in Anaheim and serves as a property manager at family-owned properties in Orange County.

Mitch Lee, term expires December 31*, *2024. Mr. Lee joined the Board in August 2021. He retired from the Boeing Company after 20 years as a Deputy Project Manager. Previously, Mr. Lee worked at Northrop Grumman Corporation for 13 years as an engineer. Throughout his career, he worked on several U.S. and international government and commercial programs. Currently, he is a consultant for MEI Machine Company regarding business/product strategy development and an advisory board member for Theory Seventy Three Corp.

Tanya Bilezikjian, PE, term expires December 31*, *2026. Ms. Bilezikjian joined the Board in January 2023. Ms. Bilezikjian is a California registered civil engineer, currently working for MNS Engineers as its Chief of Staff. During her technical career she specialized in clean water program management for large scale utilities and transportation agencies. She attended UC Irvine with a Bachelor's degree in chemical engineering and a Master's degree in environmental engineering. Ms. Bilezikjian also serves on the Board of Directors for WTS-IE, a nationwide organization that promotes women in the transportation field, and is the 2023 Conference Co-Chair for the California Storm Water Quality Association's annual conference.

History of the Electric System

The Electric System was established in 1894. The original City-owned generating plant was placed in service in 1895 and consisted of a steam-driven generator of 500 lights capacity. By 1896, the maximum capacity of the original generating plant had been reached and City voters authorized bonds for the combined rebuilding of both the electric light plant and the City's water system. In 1916, the City negotiated to purchase all of its power from Edison. In the years that followed, the City challenged rate increases and other measures undertaken by Edison, ultimately resulting in a settlement between Edison and the City in 1972 that permitted the City to take advantage of lower cost power resources.

From 1976 to 1983, the City continued to purchase a majority of its power supply from Edison. During that span, the City also purchased energy from Nevada Power and other utilities in the western United States. Also during this period, the City voters supported a series of revenue bond issues and other financing options to allow the utility to participate in a power diversification process. Included in this process was the City joining SCPPA, a joint exercise of powers authority created for planning, financing, developing, acquiring, constructing, improving, operating, and maintaining electric generating and transmission projects for participation by some or all of its members.

By the late 1980s and early 1990s, the City received power from a variety of sources, including contractual arrangements for capacity and energy, a 40 MW share of power generated at the Hoover Dam, and ownership interests in projects such as the San Juan Generating Station ("SJGS" or "San Juan") in New Mexico. As a result of the City's efforts to diversify its electric generating power resources, the City purchased less than 2% of its energy from Edison in 1997, and by 2002, the City did not purchase any of its energy requirements from Edison.

During this period, the City also began developing a project to remove overhead power lines and poles on major public roads. The City Council approved a recommendation from the Public Utilities Board to establish an underground utility conversion program in 1991, which aimed to improve the Electric System's reliability by hardening the system against outages caused by weather, metallic balloons, and vehicle accidents, while also beautifying the City's streets and enhancing property values.

Today, the City's power is produced at generating plants in or near the City and at locations across the western United States. The Electric System serves the entire area of the City, covering approximately 50 square miles of the northern portion of Orange County, which is about 28 miles southeast of downtown Los Angeles, and about 90 miles north of San Diego. The City lies on a coastal plain which is bordered by the Pacific Ocean to the west and the Santa Ana Mountains to the east. For the Fiscal Year ended June 30, 2024, the Electric System served an average of [_____] customers and sold approximately [____] megawatt-hours ("MWh") of energy to retail customers.

The table below sets forth historical Electric System resources:

TABLE 1
HISTORICAL RESOURCES
CAPACITY (MW)

	Fiscal Year Ended June 30				
	2024	**2023**	**2022**	**2021**	**2020**
Previous City-Owned Resources					
Kraemer CT Plant(1)	-	-	-	-	-
Non-City Owned Resources					
Hoover	40	40	40	40	40
IPP	236	236	236	236	236
Magnolia	118	118	118	118	118
Canyon Power Project(2)	200	200	200	200	200
Non-City Owned Renewable Resources					
Ormat Technologies	–	–	8	8	8
PPM Energy	32	32	32	32	32
Brea Power Partners	27	27	27	27	27
Cyrq Energy, Inc. subsidiary(2)	7	7	7	7	7
San Gorgonio Farm	31	31	31	31	31
MWD Hydro	10	10	10	10	10
Bowerman Power	20	20	20	20	20
Westlands (Westside Solar, LLC)	2	2	2	2	2
Loyalton (ARP Loyalton Cogen, LLC)(4)	–	–	1	1	1
Desert Harvest II	36	36	36	36	–
Total Resources	759	759	768	768	732

(1) The City ceased operation of the Kraemer CT Plant as of December 31, 2019.
(2) Cyrq Energy, Inc.'s former name was Raser Technologies.
(3) See " - Power Supply Resources - Non-City Owned Resources – Canyon Power Project" below.

(4) The City last received power from the Loyalton Project in calendar year 2020; the 1 MW shown under Fiscal Year 2022 and 2021 represents the project nameplate capacity before the City terminated its purchase power agreement on April 19, 2023.

Source: Anaheim.

The City's power supply is derived from a variety of electric generating resources in order to provide lower rates and reliable service to its customers. The City supports environmentally sound energy generation, and continues to increase renewable resources as part of its overall power portfolio. See "Power Supply Resources – Renewable Energy Resources" below.

Principal Facilities

The Electric System includes generation, transmission and distribution facilities. As of June 30, 2024, the Electric System's principal facilities consisted of approximately 1,247 circuit miles of transmission and distribution lines, and 14 distribution substations. As noted above, the City ceased operation of the Kraemer Combustion Turbine ("CT") Power Plant (the "Kraemer CT Plant") as of December 31, 2019.

The City also purchases power and transmission service from other entities. See "Power Supply Resources" below.

The following table sets forth information relating to the assets, production capacity, and production costs, per category of resource, of the Electric System for the five fiscal years shown:

TABLE 2
ELECTRIC SYSTEM STATISTICS
(Dollars in Thousands)

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Investment in Utility Plants:					
Production		$ 46,103	$ 46,103	$ 46,103	$ 46,103
Transmission		113,886	113,823	109,011	101,149
Distribution		1,292,161	1,262,770	1,194,849	1,067,042
General		163,076	161,162	154,792	151,076
Right to use asset - Land		3,200	3,200	-	-
Subscription base assets (SBITA)		658	658	-	-
Gross utility plant		1,619,084	1,587,716	1,504,755	1,365,370
Less–accumulated depreciation		(737,607)	(693,299)	(649,346)	(607,682)
Net plant in service		881,477	894,417	855,409	757,688
Land		34,243	34,243	34,243	34,243
Construction work in progress		134,139	99,346	123,368	210,135
Total utility plant		$1,049,859	$1,028,006	$1,013,020	$1,002,066
Production Costs					
Owned Generation(1)		$ 265	$ 399	$ 68	$ 805
Purchased Power(2)		232,720	208,152	192,618	201,180
Total Production Costs		$ 232,985	$ 208,551	$ 192,686	$ 201,985
Transmission-69 kV Circuit Miles		89	89	89	88
Distribution Overhead Circuit Miles		389	389	391	393
Underground Circuit Miles		769	769	764	742
Transformer Capacity (in kVA)					
220 kV to 69 kV		1,808,000	1,808,000	1,808,000	1,808,000
69 kV to 12 kV		1,325,800	1,325,800	1,325,800	1,325,800
12 kV to Customer		1,832,239	1,832,239	1,910,561	1,856,413

(1) Cost information includes debt service on facilities during the fiscal period. See " - Power Supply Resources" for discussion of reduction in City-owned generation.
(2) Excludes transmission costs and gas sold.
Source: Anaheim.

In the Fiscal Year ended June 30, 2024, the City generated and purchased approximately [____] MWh of electricity. Combined customer electric requirements created the historic distribution system peak demand of [593 MW on July 24, 2006]. The following table sets forth the total Electric System gigawatt-hours ("GWh") of energy generated and purchased and electric distribution system peak demand during the five fiscal years shown:

TABLE 3
TOTAL GIGAWATT HOURS (GWh) GENERATED AND PURCHASED AND PEAK DEMAND (MW)

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Previously Owned Generation:					
Kraemer CT[(1)]		0	0	0	0
Subtotal		0	0	0	0
Firm Purchases:					
Intermountain Power Project		761	805	1,063	1,005
Hoover		30	38	41	36
Magnolia		580	553	418	549
Canyon Power Project[(2)]		127	99	99	93
Renewable Resources[(3)]		666	732	696	693
Subtotal		2,165	2,227	2,317	2,377
Non-Firm Purchases		557	554	429	384
System Total Energy Generated and Purchased, GWh[(4)]		2,722	2,780	2,746	2,761
Distribution System Peak Demand, MW		566	487	559	530

(1) The City ceased operation of the Kraemer CT Plant in March 2019.
(2) Canyon Power Project is a peaking unit, and total generation each year varies based on demand and market prices. See " - Power Supply Resources - Non-City Owned Resources – Canyon Power Project" below.
(3) Renewable resources vary by year, but meet the RPS requirements, sometimes supplemented with renewable energy credits ("RECs").
(4) Includes energy purchased that was ultimately sold to other utilities. Also includes RECs purchased. Totals may not add due to rounding.
Source: Anaheim.

Power Supply Resources

The City's electric resources currently consist of power from firm purchases with entitlements in the IPP of the Intermountain Power Agency ("IPA"), in the Hoover Uprating Project of the federal government, in SCPPA's Magnolia Power Project and Canyon Power Project (in which the City has an entitlement to 100% of the capacity and energy thereof), and firm power purchases and non-firm energy purchases from other utilities, which can include a number of renewable energy resources. Each of these resources is more fully described below. The City's resources previously included the City-owned Kraemer CT Plant and ownership interests in the SJGS and the San Onofre Nuclear Generating Station ("SONGS"). The City has retired the Kraemer CT Plant from operation and divested its ownership interests in the latter two resources but retains certain environmental and decommissioning obligations, which are described in more detail below.

Previous City Resources

Kraemer Combustion Turbine (CT) Plant. The City owns 100% of the Kraemer CT Plant, a natural gas-fired combustion turbine plant located in the northeast part of the City, adjacent to the City's Dowling Substation. The Kraemer CT Plant began operation in May 1991 and ceased operations in March 2019 due to required turbine repairs. The City permanently ceased operation of the Kraemer CT Plant as of December 31, 2019 because the repair of the turbine was impractical and cost prohibitive due to the scarcity of repair parts for the turbine's model. Furthermore, there appeared to be only one vendor who could service and repair the turbine and that vendor was expected to cease depot repair of this turbine model on or about December 31, 2022. The City will incur costs to decommission this unit and has set aside funding for that purpose.

San Juan Generating Station Unit 4. In April 1991, the City purchased a 10.04% (50 MW) undivided ownership interest in Unit 4 of the San Juan Generating Station ("SJGS"), located in San Juan County in northwestern New Mexico, near Farmington, New Mexico. The SJGS is a four-unit coal-fired steam electric generating plant. Unit 4 had a rated net generating capability of 507 MW (as of December 31, 2017). Public Service Company of New Mexico constructed Unit 4 and manages its operations. The City purchased its 50 MW share in Unit 4 for a price of $55 million, which the City financed through revenue bonds of the Electric System. The City ceased to have an ownership interest in the SJGS effective December 31, 2017; approximately 182 GWh of energy was provided to the City from its San Juan Unit 4 ownership interest in the Fiscal Year ended June 30, 2018, prior to such date.

In connection with divestiture by the City and other participants from the plant and a restructuring thereof, the City (along with the other exiting participants) retains certain liabilities for its respective share of the costs of the SJGS decommissioning and pre-exit date mine reclamation costs. The City's exact proportionate share of such costs cannot yet be determined and will depend on a number of factors, including, among other things, the date the SJGS is ultimately retired from service. Required contributions by the City to the mine reclamation trust funds have been made and a SJGS decommissioning trust fund has been funded for the decommissioning of the plant.

San Onofre Nuclear Generating Station. Until 2007, the City's interest in the San Onofre Nuclear Generating Station ("SONGS") was the most significant City-owned generation resource in its portfolio. Under agreements with Edison, the City acquired a 3.16% ownership interest in SONGS Units 2 and 3, totaling 1,070 MW and 1,080 MW of capacity, respectively. Maintenance and operation of SONGS remained the responsibility of Edison under an operating agreement with the City (the "SONGS Operating Agreement") and other agreements with various participants. As a result of the transfer of the City's ownership interest in SONGS to Edison at the end of 2006, none of the City's firm power supply has been obtained from SONGS since 2007.

After a number of developments at the plant and numerous meetings in the public sphere and with the United States Nuclear Regulatory Commission (the "NRC"), Edison announced on June 7, 2013 its intention to permanently cease power generation operations and shut down Units 2 and 3. On September 23, 2014, Edison submitted a decommissioning cost analysis study to the NRC. Based upon Edison's most recent decommissioning cost study, amounts previously funded by the City and held in trust are expected to fully fund the City's share of SONGS decommissioning costs; however, until the actual total overall decommissioning costs are finally determined, no assurance can be given that additional contributions will not be required by the City. A decommissioning general contractor was selected in December 2016 to decontaminate and dismantle the facility. The decommissioning work is scheduled to be completed by the end of 2028, and full site restoration is expected to be completed by the end of 2049.

Non-City Owned Resources

The City purchases power from other sources pursuant to contracts. These contracts provide generally for the City to pay costs associated with the firm purchase of power (fixed costs) as well as operations, maintenance and administrative expense (variable costs). Information regarding the total cost of power purchased from these facilities is set forth in the table captioned "Electric System Statistics." With respect to each of the facilities discussed herein other than the Canyon Power Project, the City is one of several purchasers of such power and does not control the operations or management of such facility.

Intermountain Power Project. IPA constructed and placed into operation the IPP. The IPP consists of: (a) 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; (b) a ±500 kV direct current ("DC") transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current ("AC")/DC converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System" or "STS") (see "Transmission Resources – Southern Transmission System" below); (c) two 50-mile, 345-kV AC transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah, and a 144-mile, 230-kV AC transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System" or "NTS"); (d) a microwave communications system; (e) a rail car service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (f) certain water rights and coal supplies. Such 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."

Thirty-five utilities (collectively, the "IPP Purchasers") purchase the Generation Station's output. The IPP Purchasers include the City, and the California cities of Los Angeles, Riverside, Burbank, Glendale and Pasadena (the "IPP California Participants"); 23 members of IPA (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"). Pursuant to a construction management and operation agreement between IPA and the Los Angeles Department of Water and Power ("LADWP"), LADWP acts as project manager and operating agent of the IPP, responsible for, among other things, administering, operating and maintaining the IPP. The facilities of the IPP have been in commercial operation since May 1987.

The City contracted with IPA to purchase a 236 MW (13.2259%) entitlement in the capacity of the IPP plant through mid-2027. This contract obligates the City to pay in proportion to its entitlement share the costs of producing and delivering electricity (including debt service and other fixed expenses) as a cost of purchased capacity, regardless of the amount of energy scheduled to the City.

In the Fiscal Year ended June 30, 2023, the Intermountain Generating Station operated at a net plant capacity factor of approximately 35.5%. In the Fiscal Year ended June 30, 2024, the Intermountain Generating Station operated at a net plant capacity factor of approximately [___]%. The Intermountain Generating Station's coal consumption during Fiscal Year 2023-24 was approximately [____] million tons.

IPA 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 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 announced the closure of the mine in November 2023. 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, production continues to be 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. IPA 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, 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. The coal is transported primarily 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.

IPP generally maintains a minimum of 60 days of coal in inventory in the event of a coal supply disruption. At the end of May 2024, IPP maintained 106 days of coal in inventory to provide for increased generation in the summer months.

LADWP, as operator of the facility, 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 LADWP's ability to utilize such resource.

The Southern Transmission System provides transmission of IPP's output to the City and the other IPP California Participants. The City and SCPPA have entered into a transmission service contract to provide for transmission of the City's entitlement between the Generation Station and Adelanto. See "–Transmission Resources – Southern Transmission System" below. Transmission service from Adelanto to the City is provided under transmission service agreements with LADWP and transmission service under the CAISO tariff.

The current power purchase agreements with IPA are in effect until mid-2027. IPP's operations are affected by California Senate Bill 1368, which became effective in January 2007, and prohibits any investment in baseload generation that does not meet specific emissions performance standards, subject to certain exceptions. In light of that restriction and as a result of strategic discussions concerning the existing contracts' expiration, IPA developed a plan to convert the coal-fired facility to a combined-cycle natural gas-fired resource. In order to facilitate the continued participation of the IPP California Participants, the IPA Board and the IPP Participants, including the City, executed individual Second Amendatory Power Sales Contracts that allow the plant to replace the coal units with combined cycle natural gas units before 2027. The City will exit IPP upon the expiration of the current power purchase agreement in mid-2027, and does not expect to incur material costs associated with the construction of the proposed natural gas-fired units beyond 2027. Pursuant to the Second Amendatory Power Sales Contract, to the extent the existing coal units are replaced with natural gas-fired units as proposed, the City will not be responsible for future decommissioning costs associated with the IPP when the power purchase agreement expires in mid-2027. In the event that financing of the proposed natural gas-fired renewal project is not undertaken as currently proposed, the allocation of decommissioning costs to IPP Purchasers (including the City) may vary depending on the date the IPP is ultimately retired from service, what alternative project or use, if any, is instituted at the site, the level and type of remediation and/or restoration undertaken or required, and the financing options and amortization schedule for decommissioning costs.

The Utah Legislature enacted Utah Senate Bill 161 ("Utah S.B. 161"), which became effective on May 1, 2024. The reported purpose of Utah S.B. 161 was to induce IPA to amend IPA's environmental permits to provide for the operation of at least one of the IPP coal-fired units after July 1, 2025, the date by which IPA has committed to cease operation of the IPP coal units permanently. Utah S.B. 161 also required IPA to grant an option to the State of Utah for the purchase of at least one of the IPP coal-fired units with such option to be effective for two years starting on July 2, 2025. Following the enactment of Utah S.B. 161, the governor of Utah called a special session of the Utah Legislature resulting in the enactment of Utah House Bill 3004 ("Utah H.B. 3004"), which became effective on June 21, 2024. Utah H.B. 3004 repealed the provisions of Utah S.B. 161 relating to IPA amending its environmental permits. IPA continues, however, to be obligated to provide the purchase option to the State with respect to one of the IPP coal-fired units. Utah H.B. 3004 also directs a state agency, the Decommissioned Asset Disposition Authority (the "Utah Disposition Authority"), to submit an application to amend IPA's air permit to allow for a coal unit to operate after July 1, 2025. Utah H.B. 3004 also directs environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority has also been directed to determine the regulatory and commercial feasibility of operating an IPP coal unit after July 1, 2025, and to conduct a process for soliciting bids from qualified purchasers for the coal unit.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation and moved things in the right direction. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments. The City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

Hoover Uprating Project. The Hoover Uprating Project consists primarily of the uprating of the 17 generating units at Hoover Dam's hydroelectric power plant, located approximately 25 miles from Las Vegas, Nevada. The City's entitlement in the Hoover Uprating Project was approximately 40 MW. A portion of the City's Hoover entitlement became available in June 1987 and the full entitlement became available in June 1993. The Hoover Uprating Project was substantially completed on September 30, 1995. The City originally assigned its entitlement to capacity and energy of the Hoover Uprating Project to SCPPA (in return for which SCPPA financed the advancement of funds to the United States Bureau of Reclamation for costs of the Hoover Uprating Project) and executed a power sales contract with SCPPA under which the City agreed to make monthly payments on a "take-or-pay" basis for its share of SCPPA's proportionate share of Hoover capacity and allocated energy. These agreements expired on September 30, 2017.

The City renegotiated and executed replacement agreements directly with the Western Area Power Administration ("Western") and the United States Bureau of Reclamation, which became effective on October 1, 2017 and extend until September 30, 2067. The City's entitlement under the new agreements remains at approximately 40 MW. Western delivers the City's entitlement at the Mead Substation.

Magnolia Power Project. The Magnolia Power Project is a natural gas-fired, combined cycle electric generating unit with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Power Project is owned by SCPPA and is operated by the City of Burbank electric utility. The Magnolia Power Project was placed in service in September 2005 and operates in a base-load mode (8,000 hours per year or more) with staffing on a 24-hour basis. The City acquired a 38% (92 MW base capacity and 26 MW peaking capacity) entitlement in the project through a long-term power purchase agreement with SCPPA. Under its power sales agreement with SCPPA, the City is obligated to pay, on a "take-or-pay" basis, its share of the costs of the Magnolia Power Project (including operating and maintenance costs and the costs of debt service on bonds issued by SCPPA for the project) as an operating expense of the Electric System.

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 peaking capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the City. The Project is owned by SCPPA and operated and maintained by the City. The Canyon Power Project was constructed for the primary purpose of providing the City with firm capacity and energy to 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 City entered into a power sales agreement with SCPPA pursuant to which the City acquired an entitlement to 100% of the capacity and energy of the Canyon Power Project and is obligated to pay, on a "take-or-pay" basis, 100% of the costs of the project, including all operating and maintenance costs and the costs of debt service on bonds issued by SCPPA in connection with the Canyon Power Project as an operating expense of the Electric System.

The Canyon Power Project is subject to the New Source Review ("NSR") air quality permitting program promulgated by the Southern California Air Quality Management District ("SCAQMD"), the agency responsible for developing and enforcing air quality requirements in the South Coast Air Basin (the "Basin"), which includes Los Angeles, Riverside, San Bernardino and Orange Counties. The SCAQMD's NSR program is required to comply with certain provisions and requirements established pursuant to federal and State law, including the federal Clean Air Act. The federal Clean Air Act sets standards for different types of air pollutants and allows states to create plans to address pollution in areas with unclean air. These programs may include emission offset trading programs that require new sources to obtain emission reduction credits ("ERCs") for every pound of new pollution that they propose to emit.

On June 21, 2024, Canyon Power Plant Unit 1 experienced a significant mechanical failure while in full operation. The unit suffered a compressor stall, an event where high-pressure air builds up in the compressor and is redirected in the opposite direction, causing a high-pressure air explosion. This was caused when one of the compressor blades broke off from the rotor, damaging all the other blades in the compressor. As a result, the unit requires extensive repairs that are estimated to take 7 to 9 months to complete due to industry-wide supply constraints for gas turbine parts. The estimated cost for the repair is approximately $3.3 million, which includes an engineering report identifying replacement parts, turbine transportation to a depot facility, labor costs for tear-down, inspection, and analysis. Additionally, the failure of Canyon Unit 1 impacts APU's generation capacity and poses a resource adequacy (RA) issue, with an anticipated shortfall of 10 MW for September. APU anticipates the need to procure capacity at spot market prices, currently estimated at $95/KW-month. Excluding the cost of repairs, APU estimates the loss of Unit 1 for the currently expected period of 7 to 9 months will reduce net revenue by approximately $1.7 million in total, factoring in lost wholesale revenue, the cost of procuring capacity on the wholesale market, and reduced fuel expenditures.

Given that the incident occurring in June 2024 to Canyon Unit 1 is linked to a known issue with GE turbines, there is a high likelihood of similar failures occurring in the remaining three units. GE has issued a service bulletin recommending the replacement of Stage 3 through Stage 5 blades after 1,500 starts. However, Canyon Unit 1 suffered the casualty at approximately 1,000 starts, implying an immediate need to implement this service bulletin across all units. APU projects the cost of implementing this service bulletin at approximately $300,000 per unit, totaling nearly $1.0 million for the remaining three units. Currently, all other units are below the critical number of starts but require proactive maintenance to mitigate the likelihood of a similar incident.

Participation of Other Parties in Generation Resources

Each of the projects (other than the Canyon Power Project and the Hoover Uprating Project described above under "– Non-City Owned Resources") is subject to the other parties involved in those projects meeting their respective payment obligations with respect to such projects. If a party defaults on its payment obligations, then the non-defaulting parties, subject to the utilization of any reserves, may be required to expend additional funds with respect to such project. If a non-defaulting party does step-up to the payment obligation of a defaulting party, the non-defaulting party will ultimately have a right to the capability or output of the defaulting party's share of the project. See also "Indebtedness; Joint Powers Agency Obligations" below.

Renewable Energy Resources

Consistent with State legislation, the City first adopted a Renewables Portfolio Standard ("RPS") on December 16, 2011 that set a target of increasing its purchases of eligible renewable energy resources to 33% within three multi-year compliance periods though 2020. Since the adoption of the City's first RPS, Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, signed into law in October 2015, increased the statewide RPS targets to 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. Senate Bill 100, the 100 Percent Clean Energy Act of 2018, signed into law by the Governor on September 10, 2018, further increased statewide RPS targets by requiring retail electric sellers and local publicly-owned electric utilities, such as the City, 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. Senate Bill 100 established the policy of the State 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. The City met all RPS compliance targets for Compliance Period 1 (covering calendar years 2011 through 2013), Compliance Period 2 (covering calendar years 2014 through 2016), and Compliance Period 3 (covering calendar years 2017 through 2020). The City is on track to meet RPS requirements for the current compliance period (Compliance Period 4) covering calendar years 2021 through 2024 (i.e., the procurement of eligible renewable energy resources equal to at least a total of 35.75% of calendar year 2021 retail sales, 38.50% of calendar year 2022 retail sales, 41.25% of calendar year 2023 retail sales and 44% of calendar year 2024 retail sales).

The City's current renewable energy resources are described below. As a component of the Electric System rates and charges, the City implemented an Environmental Mitigation Adjustment which provides a mechanism for the recovery of the marginal cost differential between the utility's renewable power supply and its traditional carbon-based power supply that are not otherwise recovered in its rates. See "Electric Rates and Charges" below.

PPM Wind Contracts. The City purchased 32 MW of wind generated energy from PPM Energy under two separate contracts. Wind energy typically comes with a 33% load factor, so the PPM Energy contracts effectively represent 12 MW of resources. The first contract provides for delivery of 2 MW of energy 24 hours-a-day at a fixed price of $53.50 per MWh over the 20-year term of the contract, which began July 1, 2004. The second contract provides 30 MW (effectively 10 MW) at a fixed price of $55 per MWh over the 20-year term of the contract, which began July 1, 2005. The City receives energy under this contract over the Northern Transmission System at the Mona interconnection tie in the LADWP control area. The City pays for energy only when the units are operating. The 2 MW contract expired December 31, 2023, but the remaining 12 MW contract remains in place.

Brea Landfill Contracts. The City executed two power purchase agreements with Brea Power Partners, LP to deliver landfill gas renewable energy. The first short-term contract was for 5 MW with a start date of April 1, 2007 (with power received commencing July 9, 2007) from an existing facility at the Olinda Landfill through (i) the commercial operation date of a second unit or (ii) December 31, 2013. The price for energy from the Olinda Landfill project remained at $69.00 per MWh through December 31, 2008 and then increased to $71.00 per MWh on January 1, 2009, with an annual price escalation thereafter of 2% commencing January 1, 2010. In November 2012, a second long-term contract superseding the original contract was executed, which provides for a total of 27 MW from the new unit at the Olinda Landfill project upon commercial operation of the second unit, which occurred in November 2012. The term of the 27 MW contract is 33 years. The price is $112.50 per MWh with no escalation over the term of the contract. See " - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project" below.

Raser Geothermal Contract (Cyrq Energy). The City executed a power purchase agreement with a Raser Technologies subsidiary corporation for energy from an 11 MW geothermal project located in central Utah, at an initial cost of $78 per MWh with a 2% annual escalation factor for a term of 20 years. The energy is delivered to the City over the Northern Transmission System at the Mona interconnection tie in the LADWP control area, at an additional transmission cost of $2.98 per MWh. The project began commercial operation in April 2009. On or about April 29, 2011, Raser Technologies, Inc. and its Affiliated Debtors filed voluntary petitions for relief under the Bankruptcy Code. On August 30, 2011, the Bankruptcy Court confirmed the Third Amended Plan of Raser Technologies, Inc. and its Affiliated Debtors with a Plan effective date of September 9, 2011. Raser Technologies changed its name to Cyrq Energy, Inc. The Bankruptcy Court approved the reorganized subsidiary corporation's assumption of its power purchase agreement with the City. Upon the completion of a generator upgrade on November 1, 2013, an amendment to the power purchase agreement was entered into by the City with the new Cyrq Energy subsidiary to include the Ormat Energy Converter with a nameplate capacity of 14,000 gross kW. The amended agreement provides for up to 11 MW of energy for a 20-year term, expiring in 2033, with an energy cost of $98.50 per MWh and a 2% annual escalation factor, and transmission costs of $3.13 per MWh.

Metropolitan Water District Hydroelectric Contract. The City has contracted with The Metropolitan Water District of Southern California, through SCPPA, for 10 MW of hydroelectricity from a variety of small power plants located at various sites within the Los Angeles Basin. The plants operate as run-of-the-river hydro (in contrast to storage hydro) and as such, energy under the contract is "as available," much like wind. Power deliveries began November 1, 2008, at a price of $94.83 per MWh. An amendment to the agreement occurred in November 2016, reducing the purchase price to $54.71 per MWh beginning July 1, 2017. The contract expired on December 31, 2023.

San Gorgonio Wind Contract. The City executed a power purchase agreement with San Gorgonio Farms, Inc. for 31 MW of wind energy from the existing San Gorgonio Farms Wind Farm located in Whitewater, California. This facility reached commercial operation in 1983 and was originally under contract to Edison. The price for power is split between the environmental attributes and energy. Environmental attributes are priced at $38.50 per MWh with no escalation and the energy price equals the revenue paid by the CAISO for delivery of the project's energy less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. In April 2023, the City approved an amendment to the agreement with San Gorgonio Farms, Inc. resulting in an updated price of $22 per MWh and a 20-year term extension through December 31, 2033.

Bowerman Power Landfill Contract. The City executed a power purchase agreement with Bowerman Power, LLC for the purchase of 19.6 MW of energy generated from landfill gas from the Frank R. Bowerman Landfill in Irvine, California. Commercial operations began on April 27, 2016. The term of the agreement is 20 years. The generating facility is expected to produce 154 GWh annually. The annual total cost for the renewable energy and RECs is approximately $13.5 million with a 2.5% escalator during the first 10 years, 1.5% for the next five years, and no escalator thereafter. The initial price under the agreement amounts to $87.40 per MWh less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. See " - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project" below.

Westside Assets Solar Contract. The City executed a power purchase agreement with Westside Assets, LLC for 2 MW of solar energy in Kings County, California. On December 23, 2014, an amendment to the agreement clarified language and allowed for a revision to the construction schedule. This project reached commercial operation on May 9, 2016. The term of the agreement is 25 years. Power under the agreement is priced at $91.00 per MWh fixed for the term less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project.

ARP-Loyalton Biomass Project. Through SCPPA, the City contracted for the purchase of 0.81 MW of energy from the 18 MW Loyalton Biomass Project over a five-year term. American Renewable Power owned and operated the project, located in the City of Loyalton, in Sierra County, California. The project reached commercial operation on April 20, 2018. Under the agreement, the City received its proportionate share of the energy output, capacity, and associated environmental attributes from the project at an estimated cost of $638,000 per year. The agreement assisted the City towards its compliance with Senate Bill 859, passed in 2016, which requires local publicly-owned electric utilities in California that serve more than 100,000 customers to procure a proportionate share of a cumulative total of 125 MW of electric generating capacity fueled from high hazard forest materials. Calendar year 2020 marked the last year that the City received power from the Loyalton Biomass Project. 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 the Bankruptcy Code. Both cases were converted to Chapter 7 liquidation proceedings shortly thereafter and a Chapter 7 trustee was appointed. 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 termination of the power purchase agreement on April 19, 2023, counsel for SCPPA 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 SCPPA and the other power purchase agreement buyers. The parties entered into a proposed settlement agreement (the "ARP Loyalton Settlement Agreement"), which was approved by SCPPA and the other power purchase agreement buyers and submitted to the Bankruptcy Court for its approval on April 2, 2024. On May 6, 2024, the Bankruptcy Court entered an order approving the ARP Loyalton Settlement Agreement, which settlement, among other things, (a) permitted the payment of SCPPA's attorneys' fees and costs, (b) approved SCPPA's and the other buyers' release of approximately $1.1 million in proceeds from four letters of credit to the trustee, and (c) obtained a release from the Chapter 7 trustee of SCPPA's and the other buyers' obligations under the power purchase agreement. The trustee has filed his final reports, itemizing the payments he plans to make via check to professionals and other creditors from the proceeds of assets of the estates, and the Court is set to consider those reports on [November 6], 2024. Once those payments are made and all checks cashed, the trustee will close the cases.

Desert Harvest II Solar Project. Through SCPPA, the City has contracted for the purchase of 36 MW of energy from the 70 MW Desert Harvest II Solar Facility, owned by Desert Harvest II, LLC and operated by EDF Renewable Services, Inc. and located near the town of Desert Center in Riverside County, California. The project reached commercial operation on December 17, 2020. The term of the agreement is twenty-five years. Under the agreement, the City receives its proportionate share of the facility energy output and associated environmental attributes from the project at an estimated cost of $1,851,000 per year.

Haypress Hydroelectric Contract. The City has contracted with EIF Haypress for 12.5 MW of hydroelectricity from 2 small power plants located in Sierra County, California. The plants operate as run-of-river hydro and as such, energy under the contract is "as available," similar to wind. Power deliveries began January 1, 2024, at a price of $60 per MWh with an annual escalator of 2.5% beginning in the second contract year. The contract expires on December 31, 2039.

Distributed Generation; Net Metering

The City's Net Energy Metering ("NEM") Program includes 43.9 MW of participating solar capacity installed to date, which represents 7.4% of the Electric System's peak aggregated load. Under the City's NEM Program, customers are able to receive either the full retail value credit shown in energy on their bill or cash compensation for the excess energy their system generates based on the City's avoided cost of renewable electricity. The City's NEM program includes a legislative goal of 29.6 MW, 5% of the City's peak aggregated load, which was reached in May 2019. Beginning on January 1, 2021, the City launched its successor NEM Program (known as NEM 2.0), which also compensates customers for providing excess energy from their distributed energy resources, but with compensation adjusted based on the time, day, and season that the energy was supplied to Anaheim's electric grid, reflecting the dynamics of the wholesale energy market's supply and demand.

Future Power Supply; Cost of Power and Non-Firm Power

As described above, the City currently has several contracts for firm purchases of power. These contracts accounted for approximately [___]% of the City's total energy resources in the Fiscal Year ended June 30, 2024. In addition, the City can replace some of the energy otherwise available from its firm resources with energy purchased from other suppliers throughout the West. These short-term purchases are made under the Western Systems Power Pool Agreement and under bilateral agreements between the City and various suppliers. The City does this when the delivered cost of such energy is less than the variable cost of energy from its long-term resources or when additional energy is needed to meet the City's load. In the Fiscal Year ended June 30, 2024, the City purchased [____] GWh of short-term energy (about [__]% of its total energy).

With the City's executed and planned divestiture of its interests in coal facilities, SJGS in 2017 and IPP expected in 2027, and the retirement of its Kraemer CT Plant at the end of 2019, the need for additional energy and capacity will be mostly offset by renewable resources as a result of California's Senate Bill 100 RPS legislation, requiring 60% of retail sales to be derived directly from renewable energy by 2030. The small amount of capacity required to ensure the City's energy needs are met in the future, and to optimize its resource portfolio, will be met largely by short and mid-term bilateral agreements. These types of agreements will provide the City with added flexibility to better manage its Electric System resource portfolio as its load profile changes over time.

The City anticipates fulfilling its customers' energy needs through dispatching power from generating plants in which it has acquired (or may in the future acquire) an ownership share, from power sales agreements, or from short-term (monthly, weekly, daily or hourly) purchases it makes on the spot market. The cost of obtaining the necessary energy will depend upon contract requirements and the current market price for energy. Spot market prices are dependent upon such factors as the availability of generating resources in the region and weather conditions such as ambient temperatures and the amount of rainfall or snowfall. Generating unit outages, dry weather, hot or cold temperatures and time of year can all adversely impact the supply and price of energy. There is no assurance that low cost energy will be available to the City in the future, though as a participant in the Western Systems Power Pool the City will have access to market priced power. The City currently has no authority to hedge pricing for either electricity or fuel utilizing financial products. However, given that the City is fully resourced to meet its retail obligations, the amount of energy procured through market mechanisms is restricted to short durations, exclusively transacted on a spot market basis where the risk exposure for price variances is limited and can be remedied almost immediately. With respect to fuel, as described under "Fuel Supply" below, the City has procured a number of resources for long-term supplies for a portion of the natural gas requirements for the Electric System that act as a hedge against short-term price variances by providing a guaranteed supply source with a fixed known price.

Clean Energy Project. On May 20, 2024, the City entered into an electricity supply agreement with SCPPA (the "Clean Energy Purchase Contract") for the purchase of renewable energy and related attributes pursuant to SCPPA's Clean Energy Project, which is structured to assist the City with obtaining a long-term supply of power at favorable prices. Under the Clean Energy Project, SCPPA issued its $592,270,000 Southern California Public Power Authority Clean Energy Project Revenue Bonds, Series 2024A to finance the prepayment of approximately thirty years of electricity deliveries, which SCPPA will sell to the City over the term of such deliveries, in amounts and at prices as set forth in the Clean Energy Purchase Contract. The total quantity of prepaid electricity expected to be delivered during the initial delivery period, which commences on October 1, 2024 and ends on August 31, 2030 or upon earlier termination of the Clean Energy Purchase Contract, is an estimated 1.9 million MWh of electricity. The electricity that SCPPA will be selling to the City during the initial delivery period will be obtained through the assignment of two existing power purchase agreements of the City: a Renewable Power Purchase and Sale Agreement, between the City and Bowerman Power LFG, LLC, executed by the City in March 2014, and a Consolidated, Amended, and Restated Power Purchase Agreement, dated as of December 15, 2009, among the City, Brea Power Partners, L.P. and Brea Power II, LLC. The City is the only participant in the Clean Energy Project, and the City's payment obligations under the Clean Energy Purchase Contract are payable only for electricity actually received thereunder, solely from Electric System revenues.

Fuel Supply

The SCPPA Magnolia Power Project and Canyon Power Project are primarily fueled by natural gas. The City is a participant in SCPPA's Natural Gas Reserves Project and SCPPA's Prepaid Natural Gas Project, which provide the City with approximately 2,111 MMBtu of natural gas daily, or approximately 19% of the City's average daily baseload natural gas consumption. The remaining 81% of the City's average daily baseload natural gas consumption comes from short to medium term contracts (from one to ten years) and daily or monthly spot purchases.

Natural Gas Reserves Project. Through its participation in the SCPPA Natural Gas Reserves Project, the City has joined several members of SCPPA in acquiring natural gas reserves as a source of long-term supply of gas at a levelized price to provide fuel for the Magnolia Power Project. As a base-load combined-cycle facility, the City's share of fuel requirements for operating the Magnolia Power Project amounts to approximately 4.5 billion cubic feet of natural gas per year. Part of the City's overall natural gas portfolio strategy is to provide a portion of that natural gas through long-term, fixed price, gas supplies, either through long-term gas supply contracts or gas reserve field acquisitions. The SCPPA Natural Gas Reserves Project includes SCPPA'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"). On June 7, 2005, the City entered into a gas sales agreement with SCPPA pursuant to which the City purchased on a "take-or-pay" basis its entitlement share of the production capacity of the related leasehold interests in the gas reserve fields and related facilities. Pursuant to the gas sales agreement, the City's entitlement share in the Wyoming Subproject was acquired at a cost of approximately $16.4 million. The City has taken delivery of this gas since July 2005. The City's entitlement share in the Texas Subproject, which was subsequently acquired at a cost of approximately $18.6 million, also aids in supplying the City's gas needs for the Magnolia Power Project. On February 6, 2008, SCPPA issued revenue bonds for the benefit of the City and two of the other Natural Gas Reserves

Project participants in simultaneous financings in order to finance their respective shares of the acquisition costs of the Natural Gas Reserves Project.

Prepaid Natural Gas Project. The City and several members of SCPPA completed a prepaid natural gas financing to secure another source of long-term supply of gas to provide fuel for the Magnolia Power Project and other gas-fired generation stations. In connection with the prepaid natural gas financing, the City purchases on a "take-and-pay" basis natural gas acquired by SCPPA pursuant to the terms of a prepaid natural gas sales agreement between SCPPA and J. Aron & Company ("J. Aron") at a discount from the spot price over a term of approximately 27 years (as a result of restructuring as described below) beginning on July 1, 2008. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between SCPPA 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, a portion of the bonds issued by SCPPA with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured, as a result of which approximately $561,000 was remitted to the City from a lump sum payment received by SCPPA from the gas supplier. The City's restructured natural gas supply agreement with SCPPA is expected to provide approximately 13% of the City's gas requirements for the Magnolia Power Project.

Renewable Biomethane. The City has executed a renewable Biomethane Purchase and Sale Agreement with SoCal Biomethane (the "Biomethane Agreement"), a subsidiary of Anaergia, Inc., to purchase renewable biomethane derived from food waste, which has been diverted from landfills to a digestions and gas production facility outside of the City. The Biomethane Agreement was assigned from SoCal Biomethane to Rialto Bioenergy Facility, LLC ("RBF") pursuant to the Assignment and Assumption Agreement dated November 13, 2018, by and among SoCal Biomethane, RBF, and the City. Under the Biomethane Agreement, RBF has the option to produce the renewable biomethane at one of two sites located in either Bloomington or Victorville, California. Once produced, the biomethane would be delivered to the City's power generation facilities through the Southern California Gas Company's pipeline system. Electricity produced using renewable biomethane qualifies as renewable energy under California Energy Commission regulations and helps the City meet its greenhouse gas reduction goals and comply with Senate Bill 350. The renewable Biomethane Agreement provides for the purchase of up to 210,240 MMBtu per year at an initial price of $12.74/MMBtu starting in the Fiscal Year ending June 30, 2021, which escalates annually by an average of 1.4% over the 20-year term of the agreement. Delivery of biomethane from the facility continues to be delayed due to lack of adequate feedstock to produce the biomethane.

Transmission Resources

Southern Transmission System. The City is a participant in SCPPA's Southern Transmission Project. The Southern Transmission System ("STS") is an approximately 490 mile, ±500 kV DC transmission line that extends from IPP near Delta, Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end of the transmission line. The STS is owned by IPA and is one of three major components of IPP. LADWP operates and maintains the STS under contract with IPA. In connection with its entitlement to IPP, the City assigned its entitlement to capacity of the STS to SCPPA, in exchange for which SCPPA agreed to make payments-in-aid of construction of the STS and issued revenue bonds to finance the costs thereof. Pursuant to a transmission service contract with SCPPA, the City acquired a contractual entitlement to 17.647% of the transfer capability of the STS which obligates the City to pay the costs of its share of the transfer capability (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The transfer capability of the STS is currently approximately 2,400 MW (as a result of upgrades completed in December 2010). The City's entitlement in SCPPA's share of the transfer capability of the STS is approximately 423.5 MW. The City's contractual entitlement and obligation extends until 2027, consistent with the timeframe of the current power purchase agreements with IPA.

Mead-Adelanto Project*, *Authority Interest (Multiple Members). The City is a participant in SCPPA's member-related interest in the Mead-Adelanto Project. The City entered into a transmission service contract with SCPPA that provides the City with an entitlement share (approximately 118 MW) of SCPPA's member-related ownership interest (the "Authority Interest (Multiple Members)") in the Mead-Adelanto Project and obligates the City to pay for its share of the costs of SCPPA's Authority Interest (Members) in the Mead-Adelanto Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement share is 9.1666% of SCPPA's 67.9167% Authority Interest (Multiple Members) in the project. The City uses the Mead-Adelanto Project for the transmission of energy purchased by the City.

Mead-Phoenix Project, Authority Interest (Multiple Members). The City is a participant in SCPPA's member-related interest in the Mead-Phoenix Project. The Mead-Phoenix Project is an approximately 256-mile, 500-kV AC transmission line that extends from the Westwing Substation (in the vicinity of Phoenix, Arizona), connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace Substation nearby. SCPPA executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component, and a 22.4082% member-related ownership share in the Mead-Marketplace project component (collectively, the "Authority Interest (Multiple Members)") in the Mead-Phoenix Project. The Mead-Phoenix Project has an estimated transfer capability of 1,923 MW (as a result of certain upgrades completed in 2009). The City entered into a transmission service contract with SCPPA that provides the City with an entitlement to approximately 47 MW of transfer capability of the Mead-Phoenix Project and obligates the City to pay for its share (approximately 24.2%) of the costs of SCPPA's Authority Interest (Members) in the Mead-Phoenix Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement shares in the three components of the Mead-Phoenix Project are as follows: 3.615% of the Westwing-Mead project component, 8.8781% of the Mead Substation project component and 5.9395% of the Mead-Marketplace project component, respectively, of the Authority Interest (Multiple Members) in the project. The City uses the Mead-Phoenix Project for the transmission of energy purchased by the City.

Anaheim's CAISO Arrangements

The CAISO began operations on March 31, 1998. The fundamental purpose of the CAISO is to operate the transmission system in a manner that is independent of the interests of the owners of the transmission facilities to buy or sell energy. The CAISO provides transmission service and related ancillary services to all users, including the City, on a non-discriminatory basis.

In June 2002, the City notified the CAISO of its intent to become a Participating Transmission Owner ("PTO") by turning over operational control of the City's transmission entitlements. In November 2002, the City executed the Transmission Control Agreement between the CAISO and the PTOs. On January 1, 2003, the City became a PTO under the CAISO tariff by turning over operational control of its transmission entitlements to the CAISO. In return, the City receives payment of its revenue requirement for such facilities from the CAISO. The City now obtains all of its transmission scheduling requirements from the CAISO, and it procures additional required ancillary services from the CAISO or from the open competitive market. On May 1, 2020, APU submitted a proposal to the Federal Energy Regulatory Commission ("FERC") to revise its transmission revenue requirement. Effective July 1, 2020, FERC issued an order accepting APU's proposed transmission revenue requirement.

Customers and Energy Sales

The Electric System serves the entire area within the City limits (an area of approximately 50 square miles) as well as small portions of unincorporated Orange County adjacent to the City. Tables 4 and 5 below set forth the average number of customers and total electrical energy sold (in GWh) during the five fiscal years shown.

TABLE 4
AVERAGE NUMBER OF CUSTOMERS[(1)]

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Residential		105,422	104,561	103,666	103,366
Commercial		17,500	17,557	17,466	17,446
Industrial		290	273	271	290
Other		110	112	112	113
Other Utilities		11	11	11	11
Total – All Classes		123,333	122,514	121,526	121,226

(1) Average number of meters as a proxy for number of customers.
Source: Anaheim.

TABLE 5
TOTAL ENERGY SOLD
(GWh)

	Fiscal Year Ended June 30				
	2024	**2023**	**2022**	**2021**	**2020**
Residential		637	600	630	578
Commercial		731	706	660	716
Industrial		856	851	739	882
Other[(1)]		1	1	1	1
Other Utilities[(2)]		470	524	622	510
Total – All Classes[(3)]		2,695	2,682	2,652	2,687

(1) This category includes streetlights (which comprise 91% of this category) as well as outdoor lights.
(2) Reflects wholesale sales activity under prevailing market conditions.
(3) The difference between the total GWh generated and purchased shown in Table 3 captioned "Total Gigawatt Hours (GWh) Generated and Purchased and Peak Demand (MW)" and total energy sold as shown in this Table 5 is due to transmission and distribution system losses, wholesale transactions, and renewable energy credits ("RECs").
Source: Anaheim.

During the Fiscal Year ended June 30, 2024, the City satisfied 100% of its power requirements for serving retail customers from its own generation projects and through firm power purchases.

Wholesale Power

From time to time, the City has the opportunity to purchase power from and sell power to a number of power marketing firms, independent power producers, and other electric utilities, and to enter into contracts for the forward purchase and sale of electricity. The City recognizes that its wholesale market activities give rise to certain risks and has committed resources to mitigate them through the establishment of a formal risk management program. Wholesale power trading optimizes the value of the utility's assets to cost-effectively serve its retail load. The City Council approved a risk management policy (the "Policy") to provide policy guidance with respect to its wholesale trading activities. Pursuant to the Policy, the City established a Risk Management Committee (composed of the Public Utilities General Manager, the City Finance Director, the City Attorney, the Public Utilities Assistant General Managers of Finance & Energy Resources and Administration & Risk Services, the Integrated Resources Manager, the Financial Services Manager, and the Chief Risk Manager) to oversee the City's Wholesale Energy Risk Management Program (the "Program") which governs all proposed power purchase agreements, whether for retail or wholesale purposes. Pursuant to the Policy, the Program approved by the Risk Management Committee governs the various functions of the trading operations. The Policy and Program are intended to: (a) provide a common risk management infrastructure to facilitate management control and reporting; (b) create a procedure to evaluate the creditworthiness of the counterparties, and to monitor and manage the aggregate credit exposure; (c) establish a corporate culture exemplifying best practices in risk management; (d) create a mechanism to identify market-related opportunities within the City's overall exposure balance or "book"; and (e) develop an effective, streamlined ability to timely commit to transactions. The Program establishes guidelines for, among other things, authorized transaction limits, acceptable counterparty creditworthiness standards and requirements for limits on credit exposure to any individual counterparty. Most of the short-term purchase and sale transactions entered into by the utility for wholesale power opportunities are for 30 days or less.

Major Customers and Economic Conditions

APU serves a diverse customer base from a variety of industries, including tourism, hospitality, medical facility, aerospace, and telecom sectors. For the Fiscal Year ended June 30, 2024, the top 10 largest power customers of the Electric System, in terms of kilowatt hour ("kWh") sales, accounted for approximately [___]% of the Electric System's total energy sales.

A major development project occurring in Anaheim is OCVibe, a planned 95-acre development that includes new homes, shopping, dining, entertainment, hotels, office space, and parks adjacent to the Honda Center. This $4-billion expansion proposes to add 1,500 apartments with affordable housing options; four parking structures and surface lots to add more than 11,000 parking spaces; 20 acres of publicly accessible parks, trails, plazas, and other spaces; a new 5,700-seat concert venue; more than 35 restaurants with 170,000 square feet of indoor and outdoor dining space; two new hotels collectively adding 550 rooms; 1.2 million square feet of office space; and more than 80,000 square feet of shopping options. A phased opening is planned for 2028, when the Honda Center is slated to host indoor volleyball for the 2028 Summer Olympics.

Another major project is DisneylandForward, a multiyear public planning effort to expand and update Disneyland theme parks, hotel offerings, entertainment, parking, restaurants, and more. The project proposes a $1.9 billion plus investment in Anaheim over 10 years. It includes updating land use approvals from the 1990s to allow Disneyland Resort to build attractions or hotels on land originally designated for parking or other purposes.

Electric Rates and Charges

Description of Rates and Charges. The City is obligated by the Charter and by certain resolutions of the City Council under which it has electric revenue bonds outstanding to establish rates and collect charges in an amount sufficient to service the City's Electric System indebtedness, to meet its expenses of operation and maintenance and to pay other obligations payable from gross revenues, with specified requirements as to priority and coverage. The City Council establishes electric rates, which are not subject to regulation by the CPUC or by any other state agency.

The rates charged by the City to its customers are also not subject to approval by any federal agency; however, the Public Utility Regulatory Policies Act ("PURPA") requires state regulatory authorities and nonregulated electric utilities, including the City, to consider certain rate-making standards and to make certain determinations in connection therewith. The City believes that it is operating in compliance with PURPA.

The Charter requires that electric rates be based upon the cost of service to the various customer classes. As provided in Section 909 of the Charter, the City's Public Utilities Board has the power and duty to conduct all public hearings for the electric utility, including those for the consideration of utility rates and to make recommendations to the City Council concerning electric rates adopted by the City Council.

The Electric System has a number of base rate schedules. Generally, all costs of the Electric System, including power supply costs, are recovered through the application of these base rates. The City's customer rates also include a Rate Stabilization Adjustment ("RSA") that increases or decreases specifically for the recovery of the respective fluctuations in power supply, relevant operational costs, and environmental mitigation costs to meet specified financial performance indicators and goals. The goals stated within the rate schedule include the maintenance of debt service coverage ratios no less than 1.5 times and a balance in the account for deferred inflows (RSA collections) equal to approximately $50 million.

The RSA contains two components: the Power Cost Adjustment ("PCA") and the Environmental Mitigation Adjustment ("EMA"). The PCA can increase up to 1/2¢ per kWh in any 12-month period to collect for changes in power production costs, purchased power costs, regulatory compliance costs, debt service and any other costs involved in delivering energy. Additionally, if the Electric System's power supply or fuel costs increase by more than 10% over originally budgeted levels for a period of one month or longer or if the Electric System loses a major resource, such as a generation or transmission unit, then the PCA may increase by an additional 1¢ per kWh over and above the current 1/2¢ limit until all associated costs are collected at which time the PCA will be reduced to its previous level. This provision recovered costs related to an outage at IPP. The second component of the RSA, the EMA, allows for the recovery of environmental mitigation costs, such as projected greenhouse gas emissions costs, the marginal cost differential between renewable power and traditional carbon-based power, and environmental mitigation costs imposed by regulatory bodies, legislative mandates or judicial settlements, orders or decrees. The EMA is structured similarly to the PCA in that the annual limit of the increase is 1/2¢ per kWh unless costs increase by more than 10% of projections, at which point the EMA's limit on annual increases may be increased by an additional 1¢ per kWh until all associated costs are collected, and at that time the EMA will be reduced to its previous level.

The RSA collections are treated as deferred inflows for accounting purposes and are used by management to mitigate material fluctuations in the cost of energy, loss of revenues or unbudgeted costs including the unexpected long-term loss of a generating facility, unplanned limits on the ability to transmit energy to the City, or disasters that could otherwise negatively affect the revenue stream. At management's discretion, amounts in the RSA accounts may be withdrawn and recognized as gross revenues of the Electric System in order to maintain sufficient debt service coverage ratios. As of June 30, 2024, the balance in the RSA regulatory credit account, after recognition of RSA revenue for the fiscal year ending on that day, was approximately $[___] million. Management currently expects to draw down the balance on the RSA regulatory credit account gradually over the next few years, aligning the balance closer to an approximate $50 million dollar target balance.

The RSA provides the City with operational and billing flexibility. With respect to any RSA adjustment, the City first considers the result on customer bills with a goal of maintaining total electric charges that are competitive with those of other utilities in the region. Any change indicated by the RSA calculation is reviewed against other known long-term factors prior to any automatic implementation of rate changes. This allows the City to blend forecasted increases or decreases in the projected power supply or operational costs to meet the financial requirements of the City and mitigate future fluctuations in electrical costs to customers. The General Manager has the authority to adjust the RSA within prescribed guidelines.

Effective May 1, 2024, the City updated its electric rate schedule, lowering certain variable rate components with corresponding increases to base rates to better align with current costs. The PCA charge has been set to zero for all customer classes, and the EMA charge is 0.0005¢ per kWh for all customer classes. While these adjustments have been incorporated into the existing base rates, the PCA and EMA charges remain available for potential future adjustments when needed. In addition, all classes pay an undergrounding surcharge equal to 4% of base rate charges (exclusive of RSA) in order to fund the conversion of overhead power lines into underground lines throughout the City. The City does not impose a utilities' user tax.

The City's current primary rate schedules for residential, commercial and industrial customers of the Electric System are set forth in Table 6 below.

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TABLE 6
PRIMARY RATE SCHEDULES FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS
(As of May 1, 2024)

Type and Description of Service	
Domestic Services Single Family Customers (Basic):	
Customer Charge, per meter, per month	$ 8.00
Energy Charge (added to Customer Charge):	
First 10 kWh per day, cents per kWh	14.00
All Excess kWh, cents per kWh	21.49
General Service Small Commercial Customers:	
Customer Charge, per meter, per month	$ 24.00
Energy Charge (to be added to Customer Charge):	
All kWh, cents per kWh	19.60
General Service Medium Commercial Customers:	
Customer Charge	$ 56.00
Demand Charge (added to Customer Charge)	
First 15 kW or less of billing demand	166.00
All excess kW of billing demand per kW	17.13
Energy Charge (added to Demand Charge)	
All kWh, cents per kWh	13.78
General Service Large Commercial and Industrial Customers:	
Customer Charge, per meter, per month	$ 370.00
Demand Charge (to be added to Customer Charge):	
First 200 kW or less of billing demand	3,726.00
All excess kW of billing demand, per kW	21.10
Energy Charge (to be added to Demand Charge):	
For the first 540 kWh per kW of billing demand, cents per kWh	13.03
All excess kWh, cents per kWh	9.00

	Summer	Winter
Commercial Optional Time of Use Rate:		
Customer Charge, per meter, per month:	$350.00	$350.00
Demand Charge (added to Customer Charge):		
Non-Time related Maximum Demand, per kW	11.00	11.00
Plus all on-peak billing demand, per kW	19.95	N/A
Plus all mid-peak billing demand, per kW	6.98	10.93
Plus all off-peak billing demand, per kW	N/A	N/A
Energy Charge (added to Demand Charge):		
All on-peak energy, cents per kWh	17.32	N/A
Plus all mid-peak energy, cents per kWh	13.60	14.56
Plus all off-peak energy, cents per kWh	9.20	9.20

Source: Anaheim.

Average Billing Price. The table below sets forth the average billing price per kWh for the various customer classes during the five fiscal years shown (taking into account the PCA, the EMA and the 4.00% undergrounding surcharge).

TABLE 7
AVERAGE BILLING PRICE (CENTS) PER KILOWATT-HOUR
(RETAIL SALES)

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Residential		19.16	18.28	18.13	17.46
Commercial		19.86	19.61	19.38	18.69
Industrial		17.00	16.59	16.49	15.89
Other		19.44	16.70	16.63	15.84
System Averages		18.56	18.05	17.94	17.23

Source: Anaheim.

Cost Recovery and Reserves. APU's electric rates include components that largely decouple revenues from sales and allow for the timely recovery of costs and achievement of financial goals. The City Council authorized APU to employ this rate mechanism when needed, allowing for timely cost recovery, customer bill stability, and the ability to raise approximately $65 million per year without requiring a vote. These rate mechanisms, coupled with financial reserves equal to approximately 200 days of operating expenses and a $100 million revolving line of credit with Wells Fargo Bank, N.A., provide APU with the means to offset potential lost revenue from reduced retail sales and/or increased costs.

Capital Improvements Plan

As part of its planning process, the City identified the following Electric System capital improvement projects through the Fiscal Year ending June 30, 2028 (the "Five-Year Plan"), totaling approximately $479.2 million:

	Five-Year Plan 2023-24 through 2027-28 (In Thousands)
Transmission & Distribution	$ 94,700
Substation Improvements	85,100
System Undergrounding	82,900
Electric Facilities & Streetlights	75,200
Direct Buried Cable & System Expansion	62,500
Transformer Replacement	51,800
System Protection, Automation, Telecom	27,000
Total	$479,200

(1) The five-year plan shown represents projected capital expenditures only, not City Council adopted budgets. As such, figures may change based on timing of projects and expenditures, and re-prioritization of projects.

The electric capital programs aim to improve electric service reliability, enhance system resiliency, improve operational efficiencies, support system growth, and integrate renewable resources. Transmission and distribution projects replace aging overhead electrical and communication facilities with new underground facilities to improve overall system reliability, public safety, and aesthetics. Projects involving the Electric System's distribution substations include enhancements to existing substations that will improve reliability and provide sufficient flexibility and capacity for future electric load growth. System undergrounding projects place overhead electrical and communication infrastructure along Anaheim's major thoroughfares underground, including in high fire threat zone areas for wildfire mitigation. Electric facilities and streetlights include construction of a backup operations and crew quarters facility and street light additions and upgrades. Direct buried cable projects replace aged and deteriorated cable with more resilient conduit. The transformer replacement program repairs and replaces existing overhead transformers to reduce the likelihood of emergency repairs. System Protection and Automation includes the electric system automation, protection, and Supervisory Control and Data Acquisition ("SCADA") upgrades to enhance the resiliency and flexibility of the electric distribution system, while telecommunication projects upgrade and expand the fiber optic infrastructure to enable automation.

The City funds its capital plan through a combination of long-term financing, pay-as-you-go, and other resources. The City is in the bond market on a periodic basis to fund appropriate capital projects based on its planning models. The City currently anticipates it will finance approximately [31]% of the capital costs identified in the Five-Year Plan through existing and new bond proceeds. These projections may change based on deferrals of Electric System capital improvement projects or changes in the mix of financial resources used to fund capital projects.

Insurance

The Electric System participates in the City's self-insured workers' compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to the City in consideration of self-insurance premiums paid by the Electric System. Premiums for workers' compensation and general liability programs are charged to the Electric System by the City based on various allocation methods that include actual cost, trends in claims experience, exposure base, and number of participants. Premiums charged and paid totaled $4,065,000 and $[_____] for the years ended June 30, 2023 and June 30, 2024, respectively.

As of June 30, 2024, the City was fully funded for self-insured workers' compensation and general liability claims (self-insured retention levels of $2,000,000 per occurrence for workers' compensation claims and $1,000,000 per occurrence for general liability claims). Above these self-insured retention levels, the City's potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded total insurance coverage in any of the past three years, nor does management believe that there are any pending claims that will exceed total insurance coverage.

Wildfire Mitigation Measures

A portion of the Electric System service area encompasses geographical areas classified by the CPUC's Fire Threat Map as a "Tier 2" or "Tier 3" fire-threat area (i.e., an area of elevated or extreme risk from utility-associated wildfires). Within the four Tier 3 fire-threat zones within the City's boundaries (representing 13.86% of the City), approximately 98% of City-owned power lines are currently underground, and the remaining above-ground power lines in Tier 3 fire-threat zones are de-energized unless needed to be utilized for the distribution of electricity to the City. These factors significantly reduce the risk of electric infrastructure being a contributing factor to the ignition of a wildfire in extreme fire-risk areas. Approximately 0.61% of the geographical area served by the Electric System is identified as a Tier 2 fire threat zone. The City currently has in place a number of wildfire prevention strategies and emergency response measures. APU conducts routine inspections of distribution equipment, which includes the overhead system (poles and associated overhead conductors and equipment), as well as underground substructures and above surface equipment. APU performs ongoing vegetation clearance and management activities, with increased clearances established for overhead power lines in high risk fire areas. The City also has instituted emergency preparedness and response measures and protocols, including annual workforce emergency response training, the flexibility to de-energize overhead lines and re-route power during outages and emergencies with limited disruption in service, and the ability to eliminate the automatic reclosing capability of protective relays on certain transmission lines located with a Tier 3 fire-threat zone during dangerous weather conditions to require that power to a tripped line is only restored after manual inspection and confirmation that it may be operated safely. Pursuant to the California legislative requirements, the City Council approved and adopted the Anaheim Public Utilities 2023 Wildfire Mitigation Plan on June 13, 2023. Additionally, a qualified independent evaluator with experience in assessing the safe operation of electrical infrastructure reviewed Anaheim's 2023 plan, finding it comprehensive and satisfying the statutory requirements in compliance with California Public Utilities Code Section 8387. See also "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – State Legislation – Legislation Relating to Wildfires; Related Risks" in the front part of this Official Statement.

Transfers to the General Fund

Transfers of Electric System funds to the City's General Fund occur on a semi-annual basis. Under the Charter, annual transfers may not exceed 4% of gross revenues of the electric utility for the prior fiscal year.

Indebtedness; Joint Powers Agency Obligations

Direct Obligations. As of June 30, 2024, in addition to its obligations under its joint powers agency contracts (see "– Joint Powers Agency Obligations" below), the City had outstanding $641,505,000 principal amount of long-term obligations payable from Electric System revenues, consisting of installment purchase payments ("Qualified Obligations") payable by the City under installment purchase agreements with the Anaheim Housing and Public Improvements Authority ("AHPIA"), the Anaheim Public Financing Authority ("APFA"), or the California Municipal Finance Authority ("CMFA") relating to bonds issued by AHPIA, APFA, or CMFA for the benefit of the Electric System, which are payable from surplus Electric System revenues after payment of maintenance and operations expenses of the Electric System and the replenishment of certain reserves and other funds.

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The outstanding Qualified Obligations are summarized in the table below.

TABLE 8
OUTSTANDING QUALIFIED OBLIGATIONS
(as of June 30, 2024)

Issue	Date of Installment Purchase Agreement	Principal Amount Outstanding
California Municipal Finance Authority Revenue Refunding Bonds, Series 2014-A (City of Anaheim Electric Utility Distribution System Refunding)	10/01/14	$19,660,000
California Municipal Finance Authority Revenue Refunding Bonds, Series 2015-B (City of Anaheim Electric Utility Distribution System Refunding and Improvements) (1)	06/01/15	49,115,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2017-A (Electric Utility Distribution System Refunding)	12/01/17	30,005,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2020-A (Electric Utility Distribution System Improvements) (1)	03/01/20	56,465,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-B (Electric Utility Distribution System Refunding) (1)	03/01/20	107,965,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-C (Electric Utility Distribution System Refunding) (1)	03/01/20	42,340,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-A (Electric Utility Distribution System)	04/01/22	155,855,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-B (Electric Utility Generation System)	04/01/22	74,255,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-D (Electric Utility Distribution System Refunding) (Federally Taxable) (1)	04/01/22	71,750,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-E (Electric Utility Distribution System Refunding) (Forward Delivery)	04/01/22	34,095,000

(1) Target Bonds proposed to be refinanced with the 2022 Bonds. See "PLAN OF FINANCE" in the Official Statement.
Source: Anaheim.

The City has entered into an Amended and Restated Revolving Credit Agreement, dated as of December 7, 2023 (the "Revolving Credit Agreement") with Wells Fargo Bank, National Association (the "Credit Bank"), under which the City may borrow up to $100,000,000 for purposes of the Electric System. The repayment obligation of the City for amounts borrowed under the Revolving Credit Agreement for the Electric System is evidenced by Electric Revenue Anticipation Notes of the City, which are payable from and secured by surplus Electric System revenues on a basis that is junior and subordinate to the payment of the Qualified Obligations.

Any outstanding Electric System borrowings of the City under the Revolving Credit Agreement that have not been paid (which borrowings may be paid from, among other sources, proceeds of future long-term financings of the City) on or prior to the facility maturity date of the Revolving Credit Agreement (i.e., currently December 6, 2028, unless extended) will be automatically converted to term loans on such date, so long as no default or event of default by the City shall have occurred and be continuing, and all representations and warranties of the City under the Revolving Credit Agreement are true and correct in all material respects as of such date.

The Revolving Credit Agreement is also available for Water System borrowings. Borrowings for the Water System will reduce the commitment available under the Revolving Credit Agreement by an amount corresponding to such Water System borrowing.

Joint Powers Agency Obligations. As described herein, the City participates in or contracts with several joint powers agencies, including IPA and SCPPA. Obligations of the City under the agreements with IPA and SCPPA constitute maintenance and operation expenses of the Electric System payable prior to any of the payments required to be made with respect to the City's outstanding direct Electric System obligations (including the Qualified Obligations and Electric Revenue Anticipation Notes). Agreements between the City and IPA and the City and SCPPA (other than the agreement relating to SCPPA's Prepaid Natural Gas Project bonds and Clean Energy Project bonds) are on a "take-or-pay" basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements (other than the agreements relating to SCPPA's Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds) contain "step-up" provisions obligating the City to pay a share of the obligations of a defaulting participant. The City's participation and share of debt service obligation (without giving effect to any "step-up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

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TABLE 9
OUTSTANDING DEBT OF JOINT POWERS AGENCIES AND ANAHEIM'S SHARE
(as of June 3, 2024)

	Principal Amount of Outstanding Debt	Anaheim's Participation[1]	Anaheim's Share of Principal Amount of Outstanding Debt[2]
Intermountain Power Agency			
Intermountain Power Project[2]	$ 101,675,000	13.225%	$ 13,446,519
Southern California Public Power Authority			
Southern Transmission System	125,655,000	17.647	22,174,338
Magnolia Power Project[3]	210,150,000	39.683	83,394,245
Prepaid Natural Gas Project[4]	247,210,000	16.500	40,789,650
Natural Gas Reserves	17,815,000	100.000	17,815,000
Canyon Power Project	254,540,000	100.000	254,540,000
Clean Energy Project[5]	592,270,000	100.000	592,270,000
Subtotal	1,447,640,000		1,010,983,233
Total	$1,549,315,000		$1,024,429,752

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds).
(2) Reflects outstanding bonds.
(3) Excludes bonds relating solely to City of Cerritos.
(4) Not a "take-or-pay" obligation; the City must pay for contracted natural gas only to the extent delivered.
(5) Not a "take-or-pay" obligation; the City must pay for contracted electricity only to the extent delivered.
Source: Anaheim.

For the Fiscal Year ended June 30, 2024, the City estimates that payments of debt service on its joint powers agency obligations totaled approximately $[____] million. Annual debt service on the City's joint powers agency obligations is expected to decrease from this level to approximately $49.5 million in the Fiscal Year ending June 30, 2040. This projection assumes no future debt issuances and further assumes that the annual interest rate on unhedged variable rate joint powers agency debt obligations (i.e., joint powers agency obligations not otherwise fixed through interest rate swap agreements) will be 2.25%. Currently, all joint powers agency debt that Anaheim is a participant in is either fixed or fully-hedged if variable. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above and may be subject to repayment to the liquidity provider over a significantly shorter period than the originally scheduled payment of principal on the related bonds. Interest rate swap agreements entered into by joint powers agencies in connection with hedged variable rate joint powers agency obligations may be subject to early termination. In the event of early termination of a joint powers agency interest rate swap agreement, the joint powers agency could be obligated to make a substantial payment to the applicable swap provider, a corresponding amount of which termination payment (proportionate to each project participants' participation share in the related project) could be due from the applicable project participants.

Accounting Policies

The Electric System's accounting records, financial transactions and billing are computerized. The City's independent auditor performs an audit of the Electric Utility Fund of the Electric System at the same time as the other financial statements of the City are audited.

Funds of the Electric System are separated from the General Fund of the City, and the books and records are maintained separate and apart from all other funds and accounts of the City.

For further information concerning the Electric System's financial position, see the audited financial statements of the Anaheim Electric Utility Fund for the Fiscal Year ended June 30, 2024 filed on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at http://emma.msrb org. The foregoing internet address is included for reference only, and except as otherwise provided herein, the information on the internet site is not incorporated herein by this reference.

Historical Financial Results

The following table shows a summary of the financial results of the Electric System for the five Fiscal Years ended June 30, 2020 through June 30, 2024. The table also sets forth the calculation of debt service coverage of outstanding Electric System obligations for these periods.

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TABLE 10
CITY OF ANAHEIM
ELECTRIC UTILITY FUND, FINANCIAL RESULTS OF THE ELECTRIC SYSTEM
(Dollars in Thousands)

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Revenues					
Sale of electricity:					
Residential		$ 106,124	$ 100,861	$ 99,110	$ 95,299
Commercial		122,100	124,625	116,632	125,383
Industrial		120,366	122,338	112,698	130,767
Other		3,094	3,216	3,568	3,867
Other Utilities (wholesale)		35,320	20,640	27,286	14,498
Total revenue from sale of electricity		$387,004	$371,680	$359,294	$369,813
RSA revenue		58,637	40,000	35,000	17,250
Other (including general interest income)[(2)]		43,081	33,503	40,937	39,673
Total gross revenues		$488,722	$445,183	$435,231	$426,736
Expenses (excluding depreciation and amortization)					
Cost of purchased power[(3)]		$300,004	$271,293	$250,867	$265,626
Fuel and generation[(4)]		265	399	68	805
Operations & Maintenance		56,883	46,052	57,909	67,526
Right of way fee		6,227	5,042	5,530	5,668
Total expenses		$363,411	$322,786	$314,374	$339,625
Net revenues		$125,311	$122,398	$120,857	$ 87,111
Deposits to Renewal and Replacement Account		(246)	478	1,954	(397)
Surplus Revenues (a)		125,557	121,920	118,903	87,508
Qualified Obligations purchase payments (b)[(5)]		64,414	60,840	58,765	50,335
Second Lien Qualified Obligations (c)		-	-	-	815
Net revenues after debt service payments		61,143	61,080	60,138	36,358
Transfers (to) Anaheim General Fund		(16,994)	(15,239)	(16,667)	(18,322)
Transfers (to) from other Anaheim funds		253	1,422	179	277
Balance for other purposes		$ 44,402	$ 47,264	$ 43,650	$ 18,313
Qualified Obligation (incl. Second Lien) debt service coverage (a/(b+c))		1.9x	2.0x	2.0x	1.7x

(1) The decrease in electric revenue and supply costs for the 9-month stub period in 2024 compared to 2023 is primarily due to less demand stemming from cooler temperatures, reducing both revenue and costs related to generation, transmission, and wholesale energy purchases; additionally, no RSA revenue has been recognized through the end of 9-month period ending March 31, 2024. See " - Electric Rates and Charges" regarding current expectations on recognizing (or drawing down) the RSA balance over the next few years.

(2) The other revenues include transmission revenues, natural gas sales and interest income. Other revenue was restated to exclude capital grants from operation revenue based on GASB 34.

(3) Includes take-or-pay obligations with joint powers agencies. Cost of Purchased Power includes transmission costs and natural gas costs. Cost of Purchased Power reflects use of carbon allowance credits from the CARB to reduce renewable energy expenses.

(4) Fuel and generation includes all expenses associated with the operation of the Kraemer CT Plant and the SJGS Unit 4, which are no longer in operation.

(5) Refer to Table 8 above for Qualified Obligations outstanding at June 30, 2023.

Source: Anaheim.

Management's Discussion of Fiscal Year 2023-24 Operating Results

Gross revenues for the Fiscal Year ended June 30, 2023 were approximately $488.7 million, an increase of $43.5 million or 9.8% from the prior fiscal year, mainly due to higher retail and wholesale sales.

Total retail sales increased by $.6 million or 0.2% for the Fiscal Year ended June 30, 2023 compared to the prior fiscal year. Residential sales increased by approximately $5.3 million or 5.2%, primarily as a result of higher than average temperatures. Commercial and industrial sales decreased approximately $4.5 million or 1.8% compared to the previous fiscal year primarily as a result of the end of the state's stay-at-home orders which closed many businesses. Continued adoption of solar and energy efficiency measures by commercial and industrial customers also contributed to lower retail sales. APU expects to recognize approximately $58.6 million in RSA revenues to partially offset the lower sales revenues. The RSA component of APU's rate structure provides flexibility to recover costs and manage fluctuations in revenues. See also "– Electric Rates and Charges" for a discussion of the City's electric rate structure.

Wholesale sales increased approximately $14.7 million or 71.1% for the Fiscal Year ended June 30, 2023 compared to the prior fiscal year, primarily because of more wholesale energy sold.

Other revenues, comprised mainly of surplus natural gas sales, transmission revenue, and interest income, decreased by approximately $9.6 million or 28.5% for the Fiscal Year ended June 30, 2023 compared to the prior fiscal year in which transmission revenues were abnormally high due to congestion fees resulting from fires and transmission outages.

Total operating expenses for the Fiscal Year ended June 30, 2023 were approximately $363.4 million, an increase of $40.6 million or 12.6% from the prior fiscal year. Cost of purchased power was approximately $300.0 million for the Fiscal Year ended June 30, 2023, an increase of approximately $28.7 million or 10.6% from the prior fiscal year, reflecting the increased cost of power versus the prior fiscal year.

Management currently anticipates financial results for the Fiscal Year ended June 30, 2024 to be in line with prior year results, resulting in a similar coverage ratio.

Labor Relations

As of June 30, 2024, APU has a total of [___] full-time and [___] part-time authorized positions. Of this total: the International Brotherhood of Electrical Workers ("IBEW") Local 47 represents, approximately, [___] full-time and [___] part-time employees; the American Federation of State, County, and Municipal Employees District Council 36 ("AFSCME") represents approximately [___] full-time and [___] part-time employees; and the Anaheim Municipal Employees Association ("AMEA") represents [___] full-time and [___] part-time employee. The City of Anaheim and IBEW, Local 47 established a memorandum of understanding for the general unit effective January 1, 2023 through January 1, 2026, for the part time customer service unit effective January 1, 2023 through December 31, 2025, and for the professional management and part-time management units effective January 20, 2023 through January 16, 2026. The memorandum of understanding with AMEA expires July 3, 2025. The City also approved a memorandum of understanding with AFSCME effective July 1, 2023 through June 30, 2027. The City has not experienced any strike, work stoppage or other labor action by APU's employees in the last five years.

Retirement Programs

Pension Plans. The City's permanent employees, including APU's Electric System employees, are covered by the California Public Employees Retirement System ("CalPERS") through agent multiple-employer defined benefit plans administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State. CalPERS issues publicly available reports that include a full description of the pension plans regarding benefit provisions, assumptions and membership information that can be found on the CalPERS website at www.calpers ca.gov. *The foregoing* *internet address is included for reference only, and the information on the internet site is not incorporated by reference herein*.

The City's defined benefit pension plans, the Miscellaneous Plan, Police Safety Plan and Fire Safety Plan, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members (who must be public employees) and beneficiaries. No employees assigned to the Electric System participate in the Police Safety Plan or Fire Safety Plan. Benefit provisions and all other requirements of the plans are established by State statute and City ordinance. California legislation, the Public Employee's Pension Reform Act ("PEPRA") of 2013, implemented certain limits on the amount and types of compensation that may be included in calculating pension benefits and new formulas for the calculation of pension benefits, as well as certain contribution requirements for the sharing of pension benefit costs, for new employees hired on or after January 1, 2013 who meet the definition of a new member under PEPRA.

The cost of the Miscellaneous Plan is funded through bi-weekly contributions from employees and from employer contributions by the City. Miscellaneous Plan employees hired prior to January 1, 2013 are generally required to contribute 8.00% of their annual covered salary. Miscellaneous Plan members hired on or after January 1, 2013 and who have no prior membership in any California public employee retirement system are required to contribute 6.75% of their annual covered salary. The member contribution can be paid by the employee or by the City on the employee's behalf in accordance with applicable labor agreements. The majority of Miscellaneous Plan employees hired prior to January 1, 2013 contribute the full 8.00% employee contribution plus 4.00% of the employer contribution, for a total of 12.00%. For employees hired on and after January 1, 2013 that are required to contribute at an employee rate of 6.75% of annual covered salary, the entire 6.75% is paid by such employees. In accordance with applicable State law, the contribution rate for all public employers is determined annually by the actuary and is effective on the July 1 following notice of a change in rate. Funding contribution amounts are determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate applied to annual payroll is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the actuarially determined remaining amounts necessary to fund the benefits for its members, using the actuarial basis recommended by CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. CalPERS establishes and amends the employer contribution rates. Beginning with Fiscal Year 2017-18, CalPERS began collecting employer contributions toward the plan's unfunded liability as dollar amounts rather than percentage of active payroll. Miscellaneous Plan provisions and benefits in effect at June 30, 2024 are as follows: the City's required employer contribution rate for the normal cost component of required contributions for the Miscellaneous Plan was approximately 11.75% of annual covered payroll for employees hired prior to January 1, 2013, and 11.75% of annual covered payroll for employees hired after January 1, 2013; the City's contribution to the unfunded accrued liability was approximately $40,545,000.

The table below shows the recent history of the actuarial accrued liability, the market value of assets, the funded ratio and the annual covered payroll for the City's Miscellaneous Plan.

Valuation Date	Accrued Liability	Market Value of Assets	Unfunded Liability	Funded Ratio	Annual Covered Payroll
06/30/19	$1,502,706,000	$1,057,123,000	$445,583,000	70.3%	$124,366,000
06/30/20	1,543,927,000	1,084,188,000	459,739,000	70.2	124,700,000
06/30/21	1,619,285,000	1,308,881,000	310,404,000	80.8	111,733,000
06/30/22	1,681,617,000	1,183,362,000	461,482,000	71.9	119,690,000
06/30/23	1,741,021,000	1,230,615,000	510,406,000	70.7	133,453,000

Beginning with the June 30, 2013 valuation, CalPERS no longer uses an actuarial value of assets and instead uses the market value of assets to determine contribution rates per CalPERS' direct rate smoothing policy. Under its direct rate smoothing policy, CalPERS employs an amortization and smoothing policy that will pay for all gains and losses over a fixed 30-year period with the increases or decreases in the rate spread directly over a 5-year period.

The PERS Board adopted a new amortization policy effective with the June 30, 2019 actuarial valuation. Under the new policy, amortization payments are determined as a level dollar amount. Investment gains or losses are amortized over a fixed 20-year period with a 5-year ramp up at the beginning of the amortization period. Non-investment gains or losses are amortized over a fixed 20-year period with no ramps. All changes in liability due to plan amendments (other than golden handshakes) are amortized over a 20-year period with no ramps. Changes in actuarial assumptions or changes in actuarial methodology are amortized over a 20-year period with no ramps. Changes in unfunded accrued liability due to a golden handshake are amortized over a period of five years. These changes will apply only to new unfunded accrued liability bases established on or after June 30, 2019.

The City's required contributions to CalPERS fluctuate each year and include a normal cost component and a component equal to an amortized amount of the unfunded liability. Many assumptions are used to estimate the ultimate liability of pensions and the contributions that will be required to meet those obligations. The CalPERS Board of Administration has adjusted and may in the future further adjust certain assumptions used in the CalPERS actuarial valuations, which adjustments may increase the City's required contributions to CalPERS in future years. One of the most significant factors used in determining the liability and the funding requirements is the rate of return that investments will yield prior to making payments, known as the discount rate. CalPERS approved an incremental reduction in the discount rate to be used in its actuarial valuation from 7.5% to 7.0% over the three Fiscal Years 2018-19 to 2020-21. The discount rate was automatically lowered in July 2021, from 7.0% to 6.8%, due to the CalPERS investment return for Fiscal Year 2020-21. Lower discount rates result in a comparative increase in the unfunded liability and the contributions required to meet those obligations. The City cannot provide any assurances that the City's required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

The table below sets forth certain information regarding the electric utility's portion of the City's required contributions to its CalPERS Miscellaneous Plan for the Fiscal Years ended June 30, 2020 through June 30, 2024, which amounts were paid in full by the Electric System in each of such fiscal years.

City of Anaheim
Schedule of Electric Utility Pension Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2019-20	$10,285,000	$10,285,000	--	36.19%
2020-21	11,089,000	11,089,000	--	41.49
2021-22	11,318,000	11,318,000	--	39.06
2022-23	11,925,000	11,925,000	--	43.28
2023-24				

Source: Anaheim.

Effective for the Fiscal Year ended June 30, 2015, the City adopted Governmental Accounting Standards Board ("GASB") Statement No. 68, affecting the reporting of pension liabilities for accounting purposes. Under GASB Statement No. 68, the City is required to report the Net Pension Liability (i.e., the difference between the Total Pension Liability and the Pension Plan's Net Position or market value of assets) in its financial statements.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the Net Pension Liability of the City's Miscellaneous Plan for the measurement periods ended June 30, 2019 through June 30, 2023 (as reported in the City's electric utility fund audited financial statements as of the succeeding fiscal year). The electric utility's proportion of the Net Pension Liability was based on a projection of its long-term share of contributions to the pension plan relative to the projected contributions of all participating funds of the City.

	City of Anaheim Electric Utility Fund Proportionate Share of the Net Pension Liability – Miscellaneous Plan			
Measurement Period[1]	**Proportionate Share of the Net Pension Liability[2]**	**Electric Utility Share of the Net Pension Liability[2]**	**Net Position as a % of Share of Total Pension Liability**	**Share of Net Pension Liability as a % of Its Covered Payroll**
2018-19	22.2088%	$94,322,000	71.33%	343.89%
2019-20	22.2428	98,035,000	71.16	344.91
2020-21	22.6166	58,177,000	83.58	200.76
2021-22	21.9206	101,160,000	71.94	401.77
2022-23				

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date.
(2) Reflects the electric utility's share of the City's Miscellaneous Plan Net Pension Liability of $413,322,000, $424,705,000, $440,748,000, $342,652,000, $358,109,000 and $[_____] for the five Fiscal Year measurement periods of 2018-19, 2019-20, 2020-21, 2021-22 and 2022-23, respectively.
Source: Anaheim.

Retiree Health Benefits. In addition to the defined benefit pension plan described above, the City also maintains a program providing "other post-employment benefits" ("OPEB") to eligible retirees, including health care and disability coverage and death benefits. The City made significant changes to its OPEB program during Fiscal Year ended June 30, 2006. For City employees hired prior to January 1, 1996 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW), the length of service credit was frozen for all employees eligible for the benefit. Length of service, a factor in determining the amount of the benefit earned, will not accrue beyond December 31, 2005. Employees hired on or after January 1, 1996 (other than those represented by the Anaheim Police Association or the Anaheim Fire Association) are no longer eligible for City funding of all or a portion of post-employment medical benefits. For City employees represented by the IBEW who had not retired as of October 15, 2005, medical benefits only for future retirees are to be provided through a trust established by the IBEW. Benefits are determined by the trustees of the trust and the City's liability is limited to specified percentages of employee pay.

City employees hired on or after January 1, 1996 and before January 1, 2002 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW) were transitioned from the former defined benefit OPEB medical plan to a defined contribution OPEB medical plan. The City made a one-time contribution of $1,685,000 to a newly established retiree health savings account for those eligible employees. Participation in the retiree health savings account is mandatory for this transitional group of employees.

Based on eligibility status, retirees may participate in any health plan made available to active City employees. The City has several plans with different contribution levels and benefit provisions. The City's contributions vary up to 100% of annual premium cost, depending on the employee's Medicare eligibility, year of hire, age and employee group. At June 30, 2024, [___] retirees or surviving spouses met the various eligibility requirements and were receiving medical benefits.

The City's contributions toward the cost of its OPEB program are generally advance funded on an actuarial basis to a dedicated reserve, but annual contributions are not required. To pre-fund OPEB liabilities, the City participates in the California Employers' Retiree Benefit Trust, an agent multiple employer plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions that are administered by CalPERS. As of the actuarial valuation date of June 30, 2022, the unfunded liability for the City's Post-Employment Medical Benefits Program was $122,722 or 47% funded.

For Fiscal Years prior to Fiscal Year 2017-18, the City's reported annual OPEB cost (expense) was determined in accordance with the parameters of GASB Statement No. 45. The electric utility paid its allocated share of the City's annual full cost for current premiums.

Effective for Fiscal Year 2017-18, the City follows the provisions of GASB Statement No. 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("GASB No. 75") affecting the reporting of OPEB liabilities for accounting purposes. GASB No. 75 replaces the requirements of GASB Statement No. 45. GASB No. 75 establishes standards for employers with other postemployment liabilities for recognizing and measuring net OPEB liabilities, along with deferred inflows and outflows of resources, and expenses/expenditures related to the other postemployment liability. GASB No. 75 does not establish requirements for funding.

City contributions to the OPEB Plan occur as benefits are paid to retirees or contributions to the OPEB Trust. The City contributes an amount not less than the annual actuarially determined contribution measured in accordance with the parameters of GASB No. 75. The table below sets forth certain information regarding the electric utility's allocated share of the City's annual contributions to the OPEB Plan for the Fiscal Years ended June 30, 2020 through June 30, 2024, including the relation of such contributions to the actuarially determined contribution amount for such fiscal year.

City of Anaheim
Schedule of Electric Utility OPEB Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2019-20	$2,153,000	$2,153,000	--	7.86%
2020-21	1,773,000	1,773,000	(275,000)	8.04
2021-22	1,970,000	1,781,000	(189,000)	7.61
2022-23	1,774,000	1,774,000	--	6.48
2023-24				

Source: Anaheim.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the City Net OPEB Liability for the measurement periods ended June 30, 2019 and June 30, 2023 (as reported in Anaheim's electric utility fund audited financial statements as of the succeeding fiscal year).

City of Anaheim Electric Utility Fund
Proportionate Share of the Net OPEB Liability

Measurement Period(1)	Proportionate Share of the Net OPEB Liability(2)	Electric Utility Share of the Net OPEB Liability(2)	Net Position as a % of Share of Total OPEB Liability	Share of Net OPEB Liability as a % of Its Covered Payroll
2018-19	13.1411%	$21,224,000	37.15%	76.93%
2019-20	13.0617	20,912,000	37.91	76.36
2020-21	12.5016	13,395,000	53.77	52.59
2021-22	12.2649	15,052,000	46.79	58.12
2022-23				

(1) Measured using actuarial valuation as of the measurement date.
(2) Reflects the electric utility's share of the City's Net OPEB Liability of $184,851,000, $161,507,000, $160,100,000, $107,149,000, $122,722,000 and $[_____] for the fiscal year measurement periods of 2018-19, 2019-20, 2020-21, 2021-22 and 2022-23, respectively
Source: Anaheim.

Additional information regarding the City's retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Notes [10 and 11] and the Required Supplementary Information to the City's audited financial statements included in the City's annual comprehensive financial report, which may be obtained on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at http://emma.msrb org.

Litigation Affecting the Electric System

General. At any given time, the City has pending against it a number of claims and lawsuits arising out of matters usually incidental to the operation of a utility such as the Electric System. The City is of the view that, if determined adversely to the City, the actual damage awards likely to be ultimately paid with respect to any such current claims and lawsuits would not, in the aggregate, materially impair the City's ability to pay its Electric System obligations.

In addition, there are various ongoing proceedings to which the City is not a party that involve projects in which the City has an interest and which comprise a portion of the current resource portfolio of the Electric System; although the City is not a party to these such proceedings, their outcome may impact the costs and operations of the affected project.

Federal Prosecution. On August 16, 2023, former Anaheim mayor, Harry Sidhu, agreed to plead guilty to four felony charges consisting of obstruction of justice, wire fraud, and two counts of making false statements to the Federal Bureau of Investigation ("FBI") and Federal Aviation Administration ("FAA"). In his plea agreement with federal prosecutors, Mr. Sidhu admitted that he sought to become a member of the City's negotiating team and provided confidential information related to the sale of Angel Stadium of Anaheim to people working for the Angels. Mr. Sidhu's sentencing is currently scheduled for June 14, 2024.

CITY OF RIVERSIDE

The following is certain information concerning the City of Riverside ("Riverside" or the "City") and its Public Utilities Department (the "Riverside Public Utilities Department") and such Department's electric utility (the "Riverside Electric System" or the "Electric System"), prepared by Riverside for inclusion herein. This information does not purport to cover all aspects of the Riverside Electric System's business, operations and financial position. The June 30, 2024 information provided herein is preliminary and unaudited.

History of the Electric System

Riverside was a pioneer in the transmission and distribution of electric power. The municipal electric system, which was constructed in 1895, was among the first of eight such municipally-owned systems in the State of California (the "State") prior to the turn of the century. The Riverside Electric System had been fundamentally a sub-transmission and distribution system, although Riverside did generate part of its own power from 1900 to 1924. Power was purchased exclusively from Southern California Edison Company ("SCE") from 1950 to May 1976. At that time, Riverside began receiving non-firm energy purchased from the Nevada Power Company, which was delivered to Riverside by SCE. Since that time, Riverside has developed a number of other power supply resources, including the acquisition and construction of local generation assets, participation in joint powers agency projects and long and short-term power purchases with a variety of providers, as reflected above.

Management

Under the provisions of the State Constitution and Article XII of the City Charter, Riverside owns and operates both electrical and water public utility services for its residents. The Riverside Public Utilities Department exercises jurisdiction over the electric and water utilities owned, controlled and operated by Riverside. The Riverside Public Utilities Department is under the management and control of the City Manager, subject to the powers and duties vested in the Riverside Board of Public Utilities (the "Riverside Board" or the "Board") and the City Council, and is supervised by the Public Utilities General Manager who is responsible for design, construction, maintenance and operation of the electric and water utilities.

Management of the Riverside Public Utilities Department is as follows:

Mr. David A. Garcia, General Manager, holds a Bachelor of Science in Environmental Sciences from the University of California, Riverside and a master's degree in Environmental Policy and Planning from California State University, Fullerton. He is also certified as a Grade 5 Water Treatment and Distribution Operator by the California State Water Resources Control Board. Mr. Garcia has over 30 years of water utility experience throughout the Santa Ana River Watershed. He last served as the Director of Water Operations for Eastern Municipal Water District and, previously, in various management roles, including Water Operations Manager for the Riverside Public Utilities Department.

Mr. Brian Seinturier, Assistant General Manager, Finance and Administration holds a bachelor's degree in Business Administration, with an emphasis in Accounting, from the University of California, Riverside and is a Certified Public Accountant. He has over 27 years of experience in public sector accounting and finance. He has worked for Riverside Public Utilities since July 2007.

Dr. Scott M. Lesch, Assistant General Manager, Power Resources, holds a master's degree in Statistics from Carnegie Mellon University and a Ph.D. in Applied Statistics from the University of California, Riverside. He has worked for Riverside Public Utilities since 2009. Prior to joining Riverside Public Utilities, he worked for 21 years at the University of California Riverside campus as an Environmental Statistician (in the Department of Environmental Science) and as a Principal Consulting Statistician (in the Department of Statistics).

Ms. Tracy Sato, Assistant General Manager, Strategic Initiatives, holds a Bachelor of Science in Urban and Regional Planning from California Polytechnic State University, Pomona and a master's degree in Urban and Regional Planning with a specialization in Environmental Planning from Virginia Polytechnic Institute and State University. She has over 15 years of professional and technical experience as an urban planner, including several years that included GIS programming and data management, and about 13 years in the electric utility industry. She has been with the Riverside Public Utilities Department since 2017.

Mr. Daniel Honeyfield, Assistant General Manager, Energy Delivery, holds a Bachelor of Science in Electrical and Computer Engineering from California Polytechnic State University, Pomona, a Master of Business Administration, with emphasis in Technology Management, from the University of Phoenix and a professional engineering license through the State. He has over 18 years of utility experience, serving seven years as Engineering Manager for the Sacramento Municipal Utility District and in various roles for Riverside Public Utilities, including Senior Electric Utilities Engineer.

Board of Public Utilities

The Board, created by Article XII, Section 1201, of the City Charter, currently consists of nine members appointed by the City Council. As set forth in Article XII, the Board, among other things, has the power and obligation to: (1) consider the biennial budget for the Riverside Public Utilities Department during the process of its preparation and make recommendations with respect thereto to the City Council and the City Manager; (2) within the limits of the budget of the Riverside Public Utilities Department, authorize and award bids for the purchase of equipment, materials or supplies exceeding the sum of $50,000, and authorize the acquisition, construction, improvement, extension, enlargement, diminution or curtailment of all or any part of any public utility system, and no such purchase, acquisition, construction, improvement, extension, enlargement, diminution or curtailment may be made without such authorization; (3) within the limits of the budget of the Riverside Public Utilities Department, make appropriations from the contingency reserve fund for capital expenditures directly related to the appropriate utility function; (4) require of the City Manager monthly reports of receipts and expenditures of the Riverside Public Utilities Department, segregated as to each separate utility, and monthly statements of the general condition of the Riverside Public Utilities Department and its facilities; (5) establish rates for water and electric revenue producing utilities owned, controlled, or operated by the City, but subject to the approval of the City Council; (6) approve or disapprove the appointment of the Utilities General Manager, who shall be the Riverside Public Utilities Department head; (7) make such reports and recommendations to the City Council regarding the Riverside Public Utilities Department as it deems advisable; (8) designate its own secretary; and (9) exercise such other powers and perform such other duties as may be prescribed by ordinance not inconsistent with any of the provisions of the City Charter.

Employee Relations

As of July 1, 2024, 473 City employees were assigned specifically to the Riverside Electric System. Substantially all of the non-administrative City personnel assigned to the Riverside Electric System are represented by the International Brotherhood of Electrical Workers ("IBEW"). Riverside and IBEW are parties to a Memorandum of Understanding that expires on December 31, 2024. Portions of the administrative staff are represented by the Service Employees International Union ("SEIU"). Riverside and the SEIU are parties to a Memorandum of Understanding that expires on June 30, 2025. While not under a memorandum of understanding, all unrepresented employees have compensation and benefit packages approved by the City Council. On September 20, 2022, the City Council approved changes for unrepresented employees through June 2025.

The Riverside Electric System has faced no strikes or other work stoppages within the last ten years, and the City does not anticipate any in the near future.

Retirement Programs

Employee Retirement System

Retirement benefits to City employees, including those assigned to the Riverside Electric System, are provided through the City's participation in the California Public Employees Retirement System ("CalPERS"), an agency, multiple-employer, public employee retirement system that acts as a common investment and administrative agency for participating public entities within the State. CalPERS issues a separate, publicly available financial report that includes financial statements and required supplemental information of participating public entities within the State. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, Lincoln Plaza Complex, 400 Q Street, Sacramento, California 95811 or at www.calpers.ca.gov.

Riverside has a multiple tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. All of the bargaining units included in the Miscellaneous CalPERS Plan, including Management, SEIU, and IBEW employees of the Electric System and the City's water utility ("Water System"), agreed to change the calculation of the CalPERS retirement benefit for new employees from an amount derived from the highest year of salary to an amount derived from the average of the highest three years of salary, which addressed concerns associated with salary increases in the year immediately prior to retirement. This change was effective for employees hired on or after December 9, 2011.

The California Public Employees' Pension Reform Act of 2012 ("PEPRA") enacted statewide pension reforms effective January 1, 2013, which the City has implemented. Employees hired after January 1, 2013, may retire at age 62 and receive 2.0% of their highest salary for each year of service completed. The formula is adjusted to encourage employees to retire at later ages, with a 2.5% cap at age 67. The average highest three years of salary continue to be used to calculate the retirement benefit under the new plan. CalPERS also provides death and disability benefits. These benefit provisions and all other requirements are established by State statute and City ordinance.

Under the current plan, Riverside pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier -
    - The retirement formula is 2.7% at age 55 for unrepresented employees hired before October 19, 2011. Effective January 1, 2021, the employees contribute the entire required amount of 8% of their pensionable income.
    - The retirement formula is 2.7% at age 55 for SEIU employees hired before June 7, 2011. Effective November 1, 2020, employees contribute the entire required amount of 8% of their pensionable income.
    - The retirement formula is 2.7% at age 55 for IBEW employees hired before October 19, 2011. Effective January 1, 2020, employees contribute the entire required amount of 8% of their pensionable income.
- 2nd Tier - The retirement formula is 2.7% at age 55, and:
    - SEIU employees hired on or after June 7, 2011 pay their share (8%) of contributions.
    - All other Miscellaneous Plan employees hired on or after October 19, 2011 pay their share (8%) of contributions.

- 3rd Tier - The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the employee share ranging from 7% to 8% based on bargaining group classification. Classic members (employees who were CalPERS members prior to December 31, 2012) hired on or after January 1, 2013 may be placed in a different tier.

PEPRA also established a cap on the amount of compensation that can be used to calculate the retirement benefit for employees hired on or after January 1, 2013, which limits the benefit to 120% of the Social Security wage index limit for 2018 of $145,666 for employees not covered by Social Security and $121,388 for employees participating in Social Security. This cap will be adjusted annually by the Consumer Price Index for all Urban Consumers. PEPRA also prevents employers from offering defined benefit plans for compensation in excess of the cap, but does allow for contributions to a defined contribution plan for compensation in excess of the cap. PEPRA specifies that employees will not have a vested right to any employer contributions to defined contribution plans related to this provision. The City of Riverside has not made any enhancements to the compensation package for employees hired on or after January 1, 2013, with compensation exceeding the cap.

CalPERS Discount Rate Adjustment. On March 14, 2012, the CalPERS Board voted to lower the CalPERS' rate of expected price inflation and its investment rate of return (net of administrative expenses) (the "CalPERS Discount Rate") from 7.75% to 7.5%. On November 17, 2015, the CalPERS Board approved a new funding risk mitigation policy to incrementally lower the CalPERS Discount Rate by establishing a mechanism whereby such rate is reduced by a minimum of 0.05% to a maximum of 0.25% in years when investment returns outperform the existing CalPERS Discount Rate by at least four percentage points. On December 21, 2016, the CalPERS Board voted to lower the CalPERS Discount Rate to 7.0% over the three years from fiscal years 2018-19 to 2020-21. The discount rate was automatically lowered again in July 2021 from 7.0% to 6.8% due to the CalPERS investment return for fiscal year 2020-21. This remains the current discount rate as of June 30, 2024. Lowering the CalPERS Discount Rate likely means employers that contract with CalPERS to administer their pension plans (such as the City) will see increases in their normal costs and unfunded actuarial liabilities. Active members hired after January 1, 2013, under PEPRA, will likely also see their contribution rates rise.

The Electric System's total contribution to CalPERS as of June 30, 2024 and 2023 was $6,060,000 and $8,574,000, respectively. In addition, the Electric System is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005 and refinanced a portion in May 2017 (the "Pension Obligation Bonds"). The City issued additional Pension Obligation Bonds in June 2020. The Electric System's total proportionate share of the outstanding principal amount of the Pension Obligation Bonds was $58,291,000 and $63,408,000 as of June 30, 2024 and 2023, respectively, which is payable as an Operating and Maintenance Expense. That share will amortize based on the amortization schedule of the Pension Obligation Bonds. Citywide information concerning elements of the net pension liability, contributions to CalPERS and recent trend information may be found in the notes to the basic financial statements in the City's Annual Comprehensive Financial Report ("ACFR") for the Fiscal Year ended June 30, 2024, which may be obtained on the City's website after January 2025.

More recent information as to the actuarial status of the City's Miscellaneous Plan has been provided in CalPERS' Actuarial Valuation for the Miscellaneous Plan of the City of Riverside as of June 30, 2023, with respect to the City.

As shown in the table below, the report provides a recent history of the City's contribution rates for its Miscellaneous Plan, as determined by the annual actuarial valuation. The following table does not account for prepayments or benefit changes made in the middle of the year.

Table 1
City of Riverside
CalPERS Miscellaneous Plan
History of City's Contribution Rate
and Unfunded Liability Payments Due[1]

Fiscal Year	Employer Normal Cost	Unfunded Rate	Total Employer Contribution Rate	Unfunded Liability Payment Due
2011-12	11.823%	6.615%	18.438%	N/A
2012-13	11.814	6.463	18.277	N/A
2013-14	11.851	6.463	18.314	N/A
2014-15	11.554	7.440	18.994	N/A
2015-16[2]	11.871	9.141	21.012	N/A
2016-17[2]	12.250	10.728	22.978	N/A
2017-18[2]	12.136	N/A	N/A	$15,683,043
2018-19[2]	12.314	N/A	N/A	$19,422,351
2019-20[2]	12.866	N/A	N/A	$22,752,102
2020-21[3]	13.071	N/A	N/A	$24,338,697
2021-22[4]	12.730	N/A	N/A	$11,197,247
2022-23[5]	12.460	N/A	N/A	$11,860,450
2023-24[6]	13.560	N/A	N/A	$0
2024-25[7]	13.300	N/A	N/A	$4,928,524
2025-26[8]	12.930	N/A	N/A	$14,555,060

(1) Beginning with Fiscal Year 2017-18, CalPERS will collect employer contributions toward the plan's unfunded liability as dollar amounts instead of the prior method of a contribution rate. This change will address potential funding issues that could arise from a declining payroll or reduction in the number of active members in the plan. Funding the unfunded liability as a percentage of payroll could lead to the underfunding of the plans. Although employers will be invoiced at the beginning of the Fiscal Year for their unfunded liability payment, the plan's normal cost contribution will continue to be collected as a percentage of payroll.
(2) Sourced from CalPERS' Annual Valuation Report, dated July 2018. The rates reflect the effect of PEPRA enactment. PEPRA is discussed earlier in this section.
(3) Sourced from CalPERS' Annual Valuation Report, dated July 2019.
(4) Sourced from CalPERS' Annual Valuation Report, dated July 2020.
(5) Sourced from CalPERS' Annual Valuation Report, dated July 2021.
(6) Sourced from CalPERS' Annual Valuation Report, dated July 2022.
(7) Sourced from CalPERS' Annual Valuation Report, dated July 2023.
(8) Sourced from CalPERS' Actuarial Valuation for the Miscellaneous Plan of the City of Riverside as of June 30, 2023.

In addition, the report provides the recent history of the Actuarial Accrued Liability, the Market Value of Assets, the funded ratio and the annual covered payroll as shown in the table below. The funded ratio is an indicator of the short-term solvency of the plan.

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Table 2
City of Riverside
CalPERS Miscellaneous Plan
City's Funding History

Valuation Date (June 30)	Actuarial Accrued Liability	Market Value of Assets (MVA)	Funded Ratio	Annual Covered Payroll
2010	$ 952,499,597	$ 660,844,061	69.4%	$ 106,590,492
2011	998,216,259	786,080,314	78.7	108,106,192
2012	1,046,199,578	766,804,452	73.3	110,037,157
2013	1,086,925,211	847,232,156	77.9	110,552,014
2014	1,180,549,024	972,056,589	82.3	110,534,205
2015	1,228,644,007	969,285,454	78.9	111,185,202
2016	1,277,998,975	949,866,377	74.3	113,072,729
2017	1,317,421,178	1,029,759,135	78.2	118,644,799
2018	1,401,014,728	1,090,728,598	77.9	119,987,924
2019	1,462,992,745	1,138,310,022	77.8	126,381,375
2020	1,520,527,010	1,368,575,052	90.0	129,401,884
2021	1,570,873,013	1,638,143,404	104.3	128,059,046
2022	1,639,823,585	1,473,674,465	89.9	129,289,938
2023	1,752,961,359	1,517,524,223	86.6	145,914,865

Other Post-Employment Benefits

The Electric System contributes to two single-employer defined benefit healthcare plans: the Stipend Plan and the Implied Subsidy Plan. These plans provide other post-employment health care benefits ("OPEB") for eligible retirees and beneficiaries.

The Stipend Plan is available to eligible IBEW retirees and beneficiaries pursuant to their collective bargaining agreement. Benefit provisions for the Stipend Plan are established and amended through the memorandum of understanding with IBEW as approved by the City Council, which currently provides for the Electric System to make contributions on a "pay-as-you-go-basis." The union establishes the benefits paid to retirees and the City is not required by law or contractual agreement to provide funding for the plan other than as specified in the memorandum of understanding, which currently provides for a contribution of $100 per month per active IBEW employee.

The Implied Subsidy Plan allows retirees and current employees to be insured together as a group and allows a lower rate for retirees than if they were insured separately. Upon retirement, retirees pay the full amount of applicable premiums; however, they participate in the Electric System's healthcare plans and, as such, an implicit subsidy exists. The Riverside Electric System's contributions to the Implied Subsidy Plan are established by the City Council. The Riverside Electric System is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

Effective for the Fiscal Year ended June 30, 2018, the Governmental Accounting Standards Board ("GASB") issued its Statement No. 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("OPEB"). This statement requires a net OPEB liability to be reported on the balance sheet of the financial statements, similar to the net pension liability. GASB Statement No. 75 requires that most changes in the net OPEB liability be included in OPEB expense in the period of the change. For the

Fiscal Year ended June 30, 2024, the OPEB expense recorded for the Riverside Electric System was $474,000. The Riverside Electric System's net OPEB liability as of June 30, 2024 was $10,446,000.

Additional information regarding Riverside's citywide retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Note 7 to Riverside Public Utilities Department's audited Financial Statements for the Fiscal Year ended June 30, 2024, which may be obtained on the City's website after January 2025.

Electric System - General

The Riverside Electric System operates as a vertically integrated utility providing service to virtually all electric consumers within the city limits of Riverside, which encompasses 81.5 square miles. The Electric System provides service throughout the City to domestic, commercial, industrial, agricultural, municipal and other customers. In Fiscal Year 2023-24, the number of metered customers of the Electric System was 113,436.

Electric System Facilities

Power Supply

The Riverside Electric System's power supply requirements are met through:

(i) the City's internal generation consisting of 40 MW, simple cycle, combustion turbines ("Springs Generating Project") and the City's four-unit, 196 MW, power plant Riverside Energy Resource Center ("RERC") Units 1, 2, 3 and 4 and City's combined-cycle Clearwater Cogeneration Facility ("Clearwater") located in Corona, California (29.5 MW) (see the caption "—City-Owned Generating Facilities");

(ii) entitlements in the Intermountain Power Project ("IPP") Generating Station, the Hoover Power Plant and through its participation in the Southern California Public Power Authority (the "Authority"), the Authority's Palo Verde Nuclear Generating Station Project ("PVNGS") (see the caption "—Entitlements");

(iii) long-term power purchase agreements for renewable energy (see the caption "—Renewable Resources");

(iv) purchases of firm energy from various western utilities when it is available at an economical price or when needed to satisfy periods of peak demand (see the caption "—Firm Contracts and Market Purchases"); and

(v) energy purchases through the California Independent System Operator (the "CAISO") centralized markets (see the caption "—Firm Contracts and Market Purchases").

For Fiscal Year 2023-24, the overall average net cost of generation and transmission was 9.3 cents per kilowatt-hour ("kWh").

The following table sets forth the amounts in MWh and percentages of electricity obtained by Riverside during the Fiscal Year ended June 30, 2024.

Table 3
Riverside Electric System
Annual Electricity Supply [(1)]
Fiscal Year Ended June 30, 2024

Resources	MWh	Percentage
Renewable Resources	923,000	42.0%
Firm Contracts and Market Purchases	786,800	35.7
IPP Generating Station	293,600	13.4
Springs, RERC and Clearwater	68,300	3.1
PVNGS	103,000	4.7
Hoover Power Plant	23,600	1.1
Total	2,198,300	100%

(1) Includes native load (the supply for end-use customers that the Electric System is obligated to serve), losses and wholesale power sales. Reflects preliminary results based on available information to date; subject to change.

During Fiscal Year 2023-24, the Electric System generated and purchased a total of 2,198,300 megawatt hours ("MWhs") of electricity for delivery to customers throughout the City. The system peak for the Fiscal Year ended June 30, 2024 was 589.8 megawatts ("MWs") on August 29, 2023. The following table sets forth, in MWh of electricity, the total purchases of power and Riverside Electric System peak demand during the periods shown.

Table 4
Riverside Electric System
Total Energy Generated and Purchased and Peak Demand

	Fiscal Year Ended June 30,				
	2024*	2023	2022	2021	2020
From City's Own Generation (MWh)[(1)]	68,300	92,600	68,000	95,400	77,500
From Other Sources (MWh)	2,130,000	2,147,300	2,214,900	2,166,900	2,160,500
System Total (MWh)[(2)]	2,198,300	2,239,900	2,282,900	2,262,300	2,238,000
System Peak Demand (MW)	589.8	647.8	575.9	630.3	587.2
System Native Load (MWh)	2,065,000	2,161,000	2,144,000	2,122,000	2,114,000

* Reflects preliminary results based on available information to date; subject to change.
(1) Fluctuations in City generation reflect changes in energy market prices and peak electricity needs, which can vary based on weather and other circumstances.
(2) Before system losses. Excludes wholesale sales.

City-Owned Generating Facilities

City-owned generating facilities include the City's Springs Generating Project, RERC Units 1, 2, 3 and 4 and Clearwater.

Springs Generating Project. The Springs Generating Project (which began commercial operations in 2002) consists of four natural gas, simple cycle turbine generators, each with a gross capacity of 10 MW (for a total of 40 MW). The Springs Generating Project is used primarily to serve the Electric System's native load during periods of super peak power demand in the City. These facilities are also available to be used if normal operations of the Electric System are disrupted and will provide essential emergency services within the City, such as hospital care, traffic control and police and fire dispatching.

RERC Units 1, 2, 3 and 4. RERC Units 1 and 2 are natural gas-fired, simple-cycle plants located in the City, consisting of two General Electric LM 6000 SPRINT combustion turbines, nominally rated at 49 MW each (net power at site conditions) and related sub-transmission lines. The construction of the units was completed in June 2006. The units have a combined operating capacity of 98 MW with emission levels that allow for approximately 1,200 hours of run time per unit, per year. RERC Units 3 and 4 are of the same make, model and operating characteristics as RERC Units 1 and 2 and achieved commercial operation on April 1, 2011. RERC Units 3 and 4 have a combined operating capacity of 98 MW with emission levels that allow for approximately 150 hours of run time per unit, per month. All four RERC Units serve the Electric System's native load when economically feasible or during periods of peak power demand in the City, enhance reliability and service delivery to customers and provide energy and ancillary services in the CAISO markets.

Clearwater. Clearwater consists of a single, General Electric LM 2500 combustion turbine generator operating in combined cycle with one RENTECH heat recovery steam generator and one SHIN NIPPON steam turbine generator. The gross plant output of Clearwater is 29.5 MW. The City acquired Clearwater from the City of Corona, California, effective September 1, 2010. Clearwater has been included in the City's resource portfolio and the necessary air quality permits to operate Clearwater up to a baseload configuration are in place. Clearwater is also utilized by the City to meet the local resource adequacy requirements of the CAISO.

Decommissioning of SONGS. The City has a 1.79% undivided ownership interest in Units 2 and 3 of San Onofre Nuclear Generating Station ("SONGS"); however, on June 7, 2013, SCE, as principal owner and operating agent, announced its plan to retire Units 2 and 3 of SONGS permanently, triggering the start of decommissioning. Consequently, SONGS is no longer a power resource for the Electric System. The process of decommissioning the nuclear power plant is expected to take many years and is governed by Nuclear Regulatory Commission (the "NRC") regulations. According to the 2020 Decommissioning Cost Estimate provided by SCE, the total decommissioning costs for Units 2 and 3 are estimated at $5.2 billion in 2020 dollars, of which the Electric System's share is approximately $93.8 million. The Electric System has established trust accounts and a designated decommissioning reserve to accumulate resources for the decommissioning process. As of June 30, 2024, the Electric System has paid $49.5 million for its share of the decommissioning costs from the trust accounts. The remaining estimated costs of $46.1 million are expected to be fully covered by the trust accounts and the designated decommissioning reserve, which as of June 30, 2024, had values of $45.0 million and $10.9 million, respectively. Because of the uncertainty of future unknown costs, the Electric System will continue to set aside moneys in the designated decommissioning reserve in the amount of $1 million per year (as decreased beginning in Fiscal Year 2024-25). The $1 million amount has been approved by the Board and City Council and will be set aside each year unless adjusted by the Board and City Council in the future.

Fuel Supply/Procurement. The City's RERC, Springs and Clearwater generating plants are fueled by natural gas. The City procures natural gas from credit-approved counterparties for its natural gas generation plants on a monthly and daily basis. Historically, the summer months have been the City's primary focus for natural gas procurement as the City has reliability requirements to run internal generation during high load days. Additionally, natural gas procurement is needed when it is determined to be more economical to run internal generation than to buy from the CAISO energy markets. Finally, natural gas procurement is needed for City-owned generation to meet resource adequacy obligations and to meet local reliability needs of the City during significant line outages or system emergencies that can occur.

Entitlements

IPP Generating Station. The City has a 7.617% (approximately 137.1 MW) entitlement in the coal-fired IPP Generating Station Units 1 and 2 located near Lynndyl, Utah, which were declared to be commercially operational in June 1986 and May 1987, respectively. The City has entered into a power sales agreement with IPA, as the owner of IPP, which obligates the City to purchase its share of capacity and energy of IPP on a take-or-pay basis (the "IPP Contract"). The IPP Contract expires in 2027. See the caption "—Indebtedness; Joint Powers Agency Obligations." After 2027, the City expects to replace most of the power that is currently supplied through the IPP Contract with energy from new renewable resources, concurrent with its efforts to reach a 60% renewable portfolio standard by or before 2030. See the captions "—Electric System Strategic Plan—Power Resource Portfolio Management" and "—State Legislation Affecting the Power Supply."

IPP consists of: (a) two coal-fired, steam-electric generating units with net ratings of 900 MW each and a switchyard located near Lynndyl, Utah; (b) a rail car service center located in Springville, Utah; (c) certain water rights; and (d) certain transmission facilities consisting primarily of the Southern Transmission System ("STS"). See the caption "—Transmission and Distribution Facilities—Southern Transmission System."

There are 35 utilities that purchase the output of IPP, consisting of the City, and the California cities of Los Angeles, Anaheim, Burbank, Glendale and Pasadena, 23 members of IPA and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming. IPP is operated by the City of Los Angeles, through its Department of Water and Power ("LADWP").

The IPP Generating Station's annual coal requirement is approximately 3.6 million tons. LADWP, in its role as the operating agent of IPP, buys coal under contracts to fulfill this supply requirement of IPP. Coal is purchased under a portfolio of fixed price contracts that are of short- and long-term duration. Currently, the IPP Generating Station is running at approximately at a 45% capacity factor level due to challenges in obtaining additional short-term coal supply contracts. However, LADWP has sufficient long-term coal under contract to maintain this capacity factor through early 2025, when the coal units are expected to be retired. IPA attempts to maintain a coal stockpile at IPP that is sufficient to operate the plant at current plant capacity factors for about 60 days in the event of a disruption in coal supply.

Transportation of coal to IPP is provided to IPA primarily by rail under its agreements with the Utah Railway and Union Pacific Railroad companies, and the coal is transported primarily in IPA-owned railcars. Coal can also be transported, to some extent, in commercial trucks.

Under Senate Bill 1368, the City is precluded from renewing the IPP Contract at the end of its term in June 2027. See the captions "—State Legislation Affecting the Power Supply—Senate Bill 1368 – Emission Performance Standard" and "—Electric System Strategic Plan—Power Resource Portfolio Management." However, certain other parties could continue their participation.

In order to facilitate continued participation in IPP, the IPA Board of Directors issued the Second Amendatory Power Sales Contract, which amended the IPP Contract to allow the plant to replace the coal units with combined cycle natural gas units by July 1, 2025. IPA and purchasers representing 100% of IPA's generation entitlement share completed and executed the Renewal Power Sales Contract, which will allow such participants to continue taking power from IPP, fueled initially by natural gas, for the period from 2027 through 2077. After extensive discussions among IPA and the IPP participants, it was determined that the participants' demand would not support the current design capacity of the currently, contractually obligated repowering plan (the "IPP Repower Project") of 1,200 MWs. As a result, the IPP Coordinating Committee, the IPP Renewal Contract Coordinating Committee and the IPA Board of Directors concluded that it was in the best interest of the participants to downsize the future IPP Repower Project from 1,200 MW to 840 MW, and to redesign the power block. Such reduction in MWs and the change in configuration would be considered an "Alternative Repowering" under the Second Amendatory Power Sales Contract. On September 11, 2018, the City Council approved an "Alternative Repowering" for IPP and the amendments to the Second Amendatory Power Sales Contract and the Renewal Power Sales Contract. The City's entitlement share in the Alternative Repowering Project is 4.167% (35 MW).

Under provisions of the Renewal Power Sales Contract, certain California participants, including the City, had the right to exit completely from the IPP Repower Project or any Alternative Repowering by providing a written notice of termination to IPA at least 90 days prior to November 1, 2019. On May 7, 2019, the City Council authorized: (i) termination of the Renewal Power Sales Contract between IPA and the Electric System effective November 1, 2019; and (ii) the Electric System's exit from the IPP Repower Project upon the expiration date of the current Power Sales Contract on June 15, 2027.

Hoover Power Plant. The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada, and is owned and operated by the U.S. Department of the Interior's Bureau of Reclamation (the "Bureau"). The power from the project is marketed by the Western Area Power Administration ("Western"). The City has executed agreements with the Bureau and Western which became effective on October 1, 2017 and expire on September 30, 2067. The City's entitlement is approximately 30 MW (1.461% of the total project); however, due to low lake levels resulting from prolonged drought conditions, the City's available capacity entitlement has been reduced to approximately 21.24 MW as of June 30, 2024.

PVNGS. The City has a 5.4% (12 MW) entitlement interest in the Authority's 5.91% ownership interest in PVNGS, including certain associated facilities and contractual rights, 5.44% ownership in the Arizona Nuclear Power Project High Voltage Switchyard and associated contractual rights and 6.55% share of the rights to use certain portions of the Arizona Nuclear Power Project Valley Transmission System. The City has entered into a power sales agreement with the Authority that obligates the City to purchase its share of capacity and energy on a take-or-pay basis.

PVNGS consists of three nearly identical nuclear electric generating units located on an approximately 4,000-acre site about 50 miles west of Phoenix, Arizona. Units 1, 2 and 3 (each designed for a 40-year life) achieved firm operation on January 27, 1986, September 18, 1986, and January 19, 1988, respectively.

Units 1, 2 and 3 each operate under a 40-year Full-Power Operating License from the NRC. The Full-Power Operating Licenses for Units 1, 2 and 3 expire in 2025, 2026 and 2027, respectively. In April 2011, the NRC approved 20-year license extensions for all three units, allowing the three units to extend operations until 2045, 2046 and 2047, respectively. The Authority has informed the City that all other permits, licenses and approvals necessary to operate PVNGS have been secured. Arizona Public Service Company ("APS") is the Construction Manager and Operating Agent of PVNGS and the Westwing 500 kilovolt ("kV") Switchyard. The high-voltage switchyard portion of the PVNGS was constructed, and is being managed, by Salt River Project Agricultural Improvement and Power District.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. [The Authority's records indicate that the aggregate balance of the external accounts for decommissioning was $_______ as of June 30, 2024.][**update**] Based on the most recent estimate of decommissioning costs prepared by TLG Engineering in 2023, the Authority has advised the City that it estimates that the City's share of the amount required for decommissioning of was 85% funded as of December 31, 2022, which exceeds the 82% committed funding level. No assurance can be given, however, that the required funding level will be sufficient to fully fund the Authority's share of decommissioning costs at license expiration and commencement of decommissioning activities.

APS currently stores spent nuclear fuel in on-site pools near the generating units. The pools have reached capacity, and additional on-site spent fuel storage has been used until a permanent repository for high-level nuclear waste developed by the federal government becomes available. The additional onsite spent fuel storage has been provided by an independent spent fuel storage installation. The installation uses dry cask storage similar to that being used at other nuclear plants, such as SONGS, and is designed to accept all spent fuel generated by PVNGS during its lifetime.

APS ships all of its low-level radioactive waste to available disposal sites in Utah and South Carolina. In August 1995, a storage facility for low-level radioactive materials was opened at PVNGS to allow temporary on-site storage in case the disposal sites are not available. APS estimates that the storage facility has sufficient storage capacity to store all low-level radioactive waste produced at PVNGS until the end of operations. This on-site storage facility remains fully available.

Renewable Resources

In an effort to increase the share of renewable energy sources in the City's power portfolio, the City entered into power purchase agreements ("PPAs") and power sales agreements ("PSAs") with various entities described below in general on a "take-and-pay" basis. The contracts in the following tables were executed as part of compliance with Renewable Portfolio Standards mandates.

Table 5
Long-term renewable PPAs and PSAs in operation:

Supplier	Type	Maximum Contract Amount[1]	Contract Expiration
CalEnergy – Salton Sea Portfolio	Geothermal	86.0 MW	12/31/2039
Atlantica – Coso Geothermal[3]	Geothermal	10.0 MW	12/31/2041
Wintec	Wind	1.3 MW	02/19/2024
WKN Wagner	Wind	6.0 MW	12/22/2032
Terraform Power – AP North Lake	Photovoltaic	20.0 MW	08/11/2040
Onward Energy – Columbia II	Photovoltaic	11.1 MW	12/22/2034
Salka Cabazon HoldCo LLC – GPS Cabazon Wind	Wind	39.0 MW	12/31/2027
Arevon – Kingbird Solar B, LLC	Photovoltaic	14.0 MW	12/31/2036
AES			
Summer Solar	Photovoltaic	10.0 MW	12/31/2041
Antelope Big Sky Ranch	Photovoltaic	10.0 MW	12/31/2041
Antelope DSR 1 Solar	Photovoltaic	25.0 MW	12/19/2036
Arevon – Tequesquite Landfill Solar	Photovoltaic	7.3 MW	12/31/2040
Roseburg Forest Products	Biomass	N/A[2]	02/16/2026
Total		239.7 MW	

[1] All contracts are contingent on energy delivered from specific related generating facilities. The City has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Riverside Public Utilities Department.
[2] This supply is only available to satisfy SB 859 requirements.
[3] An additional 20 MW for Atlantica – Coso Geothermal is expected to be delivered by March 31, 2026 but no later than March 31, 2027. An additional 125 MW for SunZia Wind Power Co. is expected to be delivered by January 1, 2027.

Salton Sea. On May 20, 2003, the City and Salton Sea Power LLC ("Salton Sea") entered into a ten-year PPA for 20 MW of geothermal energy (the "Salton Sea PPA"). On August 23, 2005, the City Council approved an amendment to the PPA that increased the amount of renewable energy available to the City from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020.

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power (the "CalEnergy PPA"). Under the CalEnergy PPA, power is provided from a portfolio of ten geothermal generating units instead of a single generating unit, with an increasing amount of delivery that started at 20 MW in 2016, increased to 40 MW in 2019 and increased to 86 MW in 2020. The initial price under the agreement was $72.85 per MWh in calendar year 2016, which will escalate at 1.5% annually for the remaining term of the agreement. Like other renewable PPAs, the Riverside Public Utilities Department is only obligated to pay for energy that is delivered to the City.

Concurrently, the pricing under the Salton Sea PPA was amended to conform to the pricing under the CalEnergy PPA through the remaining term of the Salton Sea PPA. The pricing under the Salton Sea PPA increased by approximately $7.57 per MWh, commencing July 1, 2013, to $69.66 per MWh, with an escalation of 1.5% annually thereafter, reflecting the exchange of benefits for a substantially lower pricing under the new PPA. The cost increase under the Salton Sea PPA and accrual of the prepayment ended as of May 31, 2020. As of June 30, 2024 and 2023, the Electric System's prepayment of future contractual obligations was $11,689,000 and $12,330,000, respectively. This prepayment is recorded on the Statements of Net Position as unamortized purchased power, to be amortized over the term of the CalEnergy PPA. The CalEnergy PPA commenced in February 2016. As of June 30, 2024 and 2023, the Electric System has recorded $641,000 and $641,000, respectively, in amortization related to the unamortized purchased power.

Atlantica – Coso Geothermal. On January 15, 2021, the City entered into a 20-year PSA with the Authority for 10 MW for the first five years of the contract and 30 MW for the remaining 15 years of the contract of geothermal energy generated by Atlantica's Coso Geothermal project. The City has partnered with the Cities of Banning and Pasadena to share the Authority's contracted capacity in this project. The project began delivering power on January 1, 2022. The City's share of Coso Geothermal is expected to provide 87,500 MWh annually in the first five years of the term and 268,300 MWh for the remainder of the term at an all-in price for energy, capacity, resource adequacy, and environmental attributes of $69.00 per MWh over the term of the PSA.

Wintec. On January 28, 2003, the City entered into a 15-year renewable PPA with Wintec Energy, Ltd ("Wintec") to purchase all of the energy output generated by Wintec's wind powered electric generating units with capacity up to 5 MW. Due to unforeseen circumstances, Wintec was only able to generate capacity totaling 1.3 MW. On November 15, 2005, the City Council approved an amendment to the original agreement, reducing the capacity to 1.3 MW. The amended contract with Wintec terminated in December 2018. However, on February 12, 2019, the City Council approved an extension to the amended agreement for an additional five years at a reduced price of $35.77 per MWh. On February 19, 2024, this agreement term expired and was not extended.

WKN Wagner. On December 20, 2012, the City entered into a 20-year PPA with WKN Wagner, LLC ("WKN") for up to 6 MW of renewable wind energy and renewable energy credits from the WKN Wagner wind project in Palm Springs, California. WKN is expected to generate 21,000 MWh of renewable energy annually at a levelized cost of $73 per MWh.

Terraform Power – AP North Lake. On October 16, 2012, the City entered into a 25-year PPA with AP North Lake, LLC ("AP North") for 20 MW of solar photovoltaic energy generated by a new facility located in the City of Hemet, California. The AP North Lake Project became fully operational in August 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of $95 per MWh for the term of the PPA. After a series of ownership changes, AP North Lake is now owned by Terraform Power.

Onward Energy – Columbia II. On September 19, 2013, the City entered into a 20-year PSA with the Authority for 11.1 MW of solar photovoltaic energy generated by a facility to be built by Recurrent Energy in Kern County, California. The project, referred to as Columbia Two Solar Photovoltaic Project, has a nameplate capacity of 15 MW. On March 14, 2014, a Consent and Agreement was entered into by the Authority consenting to the transfer of ownership of the Columia Two project from Recurrent Energy to Dominion Resources. The Columbia Two Project completed construction and achieved commercial operation in December 2014. The City has a 74.3 percent share (11.1 MW) of the output from the Columbia Two Project through the Authority, which has a 15 MW PPA with Dominion Resources. The City's share of Columbia Two is approximately 33,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $69.98 per MWh over the term of the agreement. In 2021, Onward Energy, LLC became the new parent company of Columbia Two.

Salka Cabazon HoldCo LLC – GPS Cabazon Wind. On December 6, 2013, the City and FPL Energy Cabazon Wind, LLC ("Cabazon Wind") entered into a 10-year PPA for 39 MW of renewable wind energy from the Cabazon Wind Energy Center near Cabazon, California. Cabazon Wind is an existing renewable resource that has been in commercial operation since 1999. SCE purchased the output of the facility through December 2014. At the expiration of SCE's contract, Cabazon Wind entered into new interconnection and generation agreements with CAISO and SCE. The developer completed the implementation of the transition to the City as of January 1, 2015. Delivery under the PPA commenced on January 1, 2015. The project is expected to generate 71,200 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $59.30 per MWh over the term of the agreement. In 2018, after it was acquired by GlidePath Power Solutions, FPL Energy Cabazon Wind, LLC changed its name to GPS Cabazon Wind, LLC. On September 1, 2023, Salka Cabazon HoldCo LLC purchased the GPS Cabazon Wind project and assumed the remaining term of the Agreement.

Arevon – Kingbird Solar B, LLC. On September 19, 2013, the City entered into a 20-year PSA with the Authority for 14 MW of solar photovoltaic energy generated by a facility to be built by First Solar in Kern County, California. The project is referred to as the Kingbird B Solar Photovoltaic Project, with a nameplate capacity of 20 MW. The City has a 70% share of the output from the project through the Authority, who has a 20 MW PPA with Kingbird Solar B, LLC, which was acquired by Capital Dynamics in 2018. The project became commercially operational on April 30, 2016. The City's share from the project is approximately 35,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $68.75 per MWh over the term of the agreement. In 2022, Capital Dynamics was acquired by Arevon.

AES – Summer Solar, Antelope Big Sky Ranch and DSR 1 Solar. On January 17, 2013, the City entered into two 25-year PSAs with the Authority for a combined total of 20 MW of solar photovoltaic energy generated by two facilities to be built in the City of Lancaster by Silverado Power, which later changed its name to sPower after a series of ownership changes. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, and each is rated at 20 MW. The City has a 50% share of the output from each project through the Authority, which has two 20 MW PPAs for the projects. Summer Solar became commercially operational on July 25, 2016, and Antelope Big Sky Ranch became commercially operational on August 19, 2016. The City's share from the two projects totals 55,000 MWh of renewable energy per year. The price under the agreements is $71.25 per MWh over the term of the agreements. In 2021, sPower merged with the AES Corporation resulting in AES becoming the new parent company.

On July 16, 2015, the City entered into a 20-year PSA with the Authority for 25 MW of solar photovoltaic energy generated by AES's Antelope DSR Solar 1 PV Project in the City of Lancaster, California. The City has a 50% share of the output from the project through the Authority, which has a 50 MW PPA with AES. The project became commercially operational on December 20, 2016. The City's share of Antelope DSR 1 Solar is expected to generate approximately 71,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $53.75 per MWh over the term of the agreement.

Arevon – Tequesquite Landfill Solar. On March 11, 2014, the City and Solar Star California XXXI, LLC ("Solar Star") entered into a 25-year PPA for 7.3 MW of solar photovoltaic energy generated by a facility to be built on the City-owned Tequesquite Landfill. The project was fully commissioned and operational on September 30, 2015 and is expected to generate approximately 15,000 MWh of renewable energy per year. The all-in price for energy, capacity and environmental attributes was initially $81.30 per MWh, escalating at 1.5% annually. In 2018, Capital Dynamics became the new parent company of Solar Star after acquiring it from SunPower. In 2022, Capital Dynamics was acquired by Arevon.

Roseburg Forest Products. On February 16, 2021, the City entered into a 5-year SB 859 Purchase Agreement with Roseburg Forest Products Co for the remaining 0.5 MW of SB 859 compliance. The City has a 4.48% share of the output of the project along with the Authority, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, for a total capacity of 11 MW with Roseburg. The project began delivery on February 16, 2021. The price for the SB 859 compliant capacity is $46.00 per MWh over the term of the agreement.

SunZia Wind Power Co. In addition to the agreements that are described in Table 5 above with respect to projects that are currently in operation, on November 8, 2023, the City entered into a 15-year Renewable Power Purchase and Sale Agreement with SunZia Wind Power Co, LLC for 125 MW from the wind-powered electricity generating facility to be constructed between 2024 and 2026 in New Mexico. The project is expected to provide an additional 369,000 to 390,000 MWh per year of long-term renewable energy to Riverside. The facility will provide energy, capacity, resource adequacy, and environmental attributes at an all-in price of $59.50 per MWh throughout the term of the agreement. The project is expected to begin delivery by March 31, 2026 with an enforceable guaranteed delivery date of September 30, 2026.

Firm Contracts and Market Purchases

The City supplements the energy available from its firm resources with energy purchased from other suppliers throughout the western United States, as well as the CAISO Integrated Forward Market and real time market. These purchases are made under the Western Systems Power Pool ("WSPP") Agreement and numerous short-term bilateral agreements between the City and various suppliers. Energy purchases in the CAISO markets are made under the FERC-approved CAISO Tariff.

In Fiscal Years 2022-23 and 2023-24, the City purchased 625,000 MWh and 786,800 MWh, respectively, of firm energy (approximately 27.9% and 35.7%, respectively, of its total energy supply) through short-term contracts. These purchases were from WSPP counterparties, with energy ultimately being served through the CAISO Integrated Forward Market. The cost of obtaining the necessary energy depends upon contract requirements and the current market price for energy. Spot market prices are dependent upon such factors as natural gas prices, the availability of generating resources in the region, fuel type and weather conditions such as ambient temperatures and the amount of rainfall or snowfall. Generating unit outages, dry weather, hot or cold temperatures, time of year, transmission constraints and other factors can all affect the supply and price of energy.

Wholesale Power Trading Policies and Risk Management.

In October 1998, the City Council adopted formal policies for the administration of energy risk management activities within the Power Resources Division of the Electric System. These policies define the limits for power trading activities to mitigate and reduce risks associated with this business activity. Riverside also appointed an Energy Risk Manager in 1999 to oversee the development, implementation, and ongoing monitoring of a formalized financial risk management program for power supply activities. Since 1998, the policies have been reviewed on an annual basis and recommended changes have been periodically adopted by the City Council.

The policies incorporate changes in regulatory and legislative requirements, including an amendment to authorized transactions, organizational structure, and reporting requirements. The comprehensive updated policies were approved by the Riverside Board and City Council on February 1, 2013 and March 5, 2013, respectively, and include an Energy Risk Management Policy, a Wholesale Counterparty Risk Management Policy and an Authorized Transactions Policy. The Wholesale Counterparty Risk Management Policy was amended for non-substantive changes on April 29, 2014.

California Independent System Operator

Riverside serves as its own Scheduling Coordinator with the CAISO and serves as the scheduling agent, under separate Utility Service Agreements, for the Cities of Banning and Rancho Cucamonga. In addition, Riverside serves as the scheduling agent for the Authority's Columbia II Solar, Kingbird B Solar, Summer Solar and Antelope DSR 1 Solar projects under various Scheduling Coordinator Agreements. Services under the referenced agreements include day-ahead and real time scheduling of power from various sources, after-the-fact validation and settlement of transactions, and billing and payments.

On July 10, 2002, Riverside notified the CAISO of its intent to become a Participating Transmission Owner ("PTO") by turning over operational control of Riverside's transmission entitlements (the "CAISO-Transferred Entitlements") to the CAISO effective January 1, 2003. In November 2002, Riverside executed the Transmission Control Agreement ("TCA") between the CAISO and the PTOs.

Certain of Riverside's CAISO-Transferred Entitlements relate to transmission facilities, including STS, which were financed by the Authority utilizing tax-exempt bonds (the "Authority's Bonds"). Riverside executed certain transmission service contracts with the Authority that prohibit Riverside from taking any action that would adversely affect the tax-exempt status of the Authority's Bonds. If Riverside were to be found to have breached such contractual obligation, Riverside could be subjected to significant financial liability. The TCA executed by Riverside and submitted by the CAISO on November 19, 2002 for approval by the Federal Energy Regulatory Commission ("FERC") contained certain withdrawal provisions which Riverside believes will protect the tax-exempt status of the Authority's Bonds and satisfy Riverside's contractual obligation to the Authority under its transmission service contracts. To date, the Authority has received no notices affecting the tax-exempt status of the Authority's Bonds issued for projects in which the City is a participant.

On January 1, 2003, Riverside became a PTO with the CAISO, entitling Riverside to receive compensation for the use of its transmission entitlements committed to the CAISO's operational control. The amount of compensation to which Riverside is entitled is based upon Riverside's Transmission Revenue Requirement ("TRR") as approved by FERC. Included in Riverside's TRR are all costs associated with Riverside's participation in the Authority's transmission projects (STS and Mead-Adelanto and Mead-Phoenix transmission projects). Riverside obtains all of its transmission entitlements from the CAISO.

Since becoming a PTO with the CAISO, Riverside has filed three TRR's with FERC. Riverside's base TRR is adjusted annually for (among other things) automatic pass throughs of certain costs approved by FERC. For Fiscal Year ended June 30, 2024, Riverside collected $39.9 million in TRR revenue.

Transmission and Distribution Facilities

The paragraphs that follow describe the City's transmission facilities and entitlements and distribution facilities.

Southern Transmission System. STS is one of three major components of IPP. In connection with its entitlement to IPP, the City assigned its entitlement to capacity of STS to the Authority, in exchange for which the Authority agreed to make payments-in-aid of construction of STS and issued revenue bonds to finance the costs thereof. Pursuant to a transmission service contract with the Authority, the City acquired a 10.2% (195 MW) entitlement in the Authority's share of the transfer capability of STS. The City's contractual entitlement extends until June 2027. See the caption "—Indebtedness; Joint Powers Agency Obligations." Among other things, STS provides for the transmission of energy from IPP to the California transmission grid.

The STS consists of the following: (a) the AC/DC Intermountain Converter Station adjacent to the IPP Generating Station's AC switchyard in Utah; (b) the ±500 kV DC bi-pole transmission line (the "HVDC transmission line"), which is 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California; (c) the AC/DC Adelanto Converter Station, where STS connects to the switching and transmission facilities of LADWP; and (d) related microwave communication system facilities. The HVDC transmission line is capable of transmitting an amount of power that exceeds the aggregate output of the IPP Generating Station to be delivered to the Authority participants. The AC/DC converter stations each consist of two solid state converter valve groups and have a combined rating of 2,400 MW (upgraded from 1,920 MW in 2010, increasing the City's total entitlement in STS from 195 MW to 244 MW). The microwave communication facilities are used for IPP Generating Station dispatch, communication and control and protection of STS. The microwave facilities are located along two routes between the IPP Generating Station and the Adelanto Switching Station, forming a looped network.

Pursuant to the City's transmission service contract with the Authority, the City is obligated to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with STS on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations."

Mead-Phoenix Transmission Project. Originally in connection with its entitlement to PVNGS power, the City acquired a 4.0% (12 MW) entitlement in the Authority's member-related ownership share of the Mead-Phoenix Transmission Project ("Mead-Phoenix"), which is separate from the Authority interest acquired on behalf of Western and the Authority interest later acquired on behalf of LADWP only. The City has entered into a transmission service contract with the Authority that obligates the City to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with the Authority member-related interest in Mead-Phoenix on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations."

Mead-Phoenix consists of a 256-mile, 500-kV 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 at Western's existing Mead Substation in southern Nevada with transfer capability of 1,923 MW (as a result of upgrades completed in 2009, increasing the City's total entitlement in the Mead-Phoenix from 12 MW to 18 MW). By connecting to Marketplace Substation, Mead-Phoenix interconnects with the Mead-Adelanto Transmission Project (as described below) and with the McCullough Substation. Mead-Phoenix is comprised of three project components. The Authority has executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component and a 22.4082% member-related ownership share in the Mead-Marketplace project component. Other owners of the line are APS, Salt River Project and Startrans IO, L.L.C. ("Startrans"). The project entered commercial operation on May 15, 1996.

Mead-Adelanto Transmission Project. In connection with Mead-Phoenix, the City has acquired a 13.5% (118 MW) entitlement to the Authority's member-related ownership share of the Mead-Adelanto Transmission Project ("Mead-Adelanto"), which is separate from the Authority interest acquired on behalf of Western and the Authority interest later acquired on behalf of LADWP only. Mead-Adelanto consists of a 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. By connecting to Marketplace Substation, the line interconnects with Mead-Phoenix and the existing McCullough Substation in southern Nevada. The line has a transfer capability of 1,291 MW. The Authority has executed an ownership agreement providing it with a total of a 67.9167% member-related ownership share in the project. The other owner of the line is Startrans. The City has entered into a transmission service contract with the Authority that obligates the City to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with Mead-Adelanto on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations." The project entered commercial operation on May 15, 1996, which coincided with the commencement of operations by Mead-Phoenix.

Sub-Transmission and Distribution

Power is supplied to Riverside through seven separate, 69,000-volt, sub-transmission lines from a substation that is owned and operated by SCE. These lines are used for the sole purpose of delivering electric energy from SCE's Vista Substation to the northerly limits of Riverside. Each of the 69,000-volt sub-transmission lines are then interconnected to the Riverside-owned and -operated 69,000-volt sub-transmission system at multiple substations.

As of June 30, 2024, Riverside had 99.2 circuit miles of sub-transmission and 1,358 circuit miles of distribution lines, of which approximately 846 circuit miles are underground. There are 16 substations, with a combined capacity of 1,465 million volt-amperes ("MVA"). Riverside is currently undertaking the Riverside Transmission Reliability Project ("RTRP"), a joint City-SCE project which includes the construction of a 230-69 kV transmission substation. RTRP will provide a second point of interconnection to the California transmission grid, and the addition of new 69 kV transmission lines to transmit power from the new substation and distribute energy to Riverside's local distribution substations. The costs of the RTRP to date have been partially financed by electric system revenue bonds issued by the City in 2008 and 2010 and the City may elect to issue an additional series of electric revenue bonds in or about 2029 to finance further RTRP construction costs. In addition, on December 4, 2007, Riverside added a reliability charge to its electric rates to assist with funding Riverside's portion of the costs of RTRP.

The California Public Utilities Commission (the "CPUC") issued a final Subsequent Environmental Impact Report (the "SEIR") on October 2, 2018, marking the completion of the CPUC's California Environmental Quality Act review process.

Capital Improvement Program

As part of its budget and planning process, Riverside prepared a five-year Electric System Capital Improvement Program ("CIP") for Fiscal Years ending June 30, 2025 through June 30, 2029, totaling approximately $339.0 million, subject to adjustment as project cost estimates change:

	Five-Year CIP[(1)] (Dollars in Millions) Fiscal Years 2025-2029
Overhead	$ 52,797
Underground	74,722
Substation	83,674
Recurring/Obligation to Serve	88,542
System Automation	39,229
Total	**$338,964**

(1) Excludes RTRP construction costs.

The five-year CIP is supported by the Electric System's rate plan and addresses the need to replace and modernize the most vital portions of Riverside's aging electric infrastructure. Overhead and underground projects include the rehabilitation and replacement of overhead equipment, such as poles, wires, transformers, and streetlights and underground equipment such as conduits and cables in order to improve the safety, efficiency and reliability of the electric system. Substation projects include improvements to neighborhood power stations to efficiently distribute power throughout the service area. Recurring projects relate to the Electric System's obligation to serve new incoming load. System automation projects include projects for technology, security and system automation tools and applications to improve cyber security and overall efficiency. The five-year CIP is expected to be funded from proceeds of certain series of electric system revenue bonds issued by the City, with the balance to be funded by a combination of rates, reserves and other resources. On February 1, 2024, the City issued its Electric Revenue Bonds, Issue of 2024A, and the City expects to issue additional series of electric system revenue bonds in 2027 (the "2027 Bonds"). The 2027 Bonds have not yet been approved by the City Council and there can be no assurance that they will be issued at the time that is currently contemplated.

Customers and Energy Sales

The following tables set forth the number of meters as of the Fiscal Year end and total energy sold during the periods presented.

Table 6
Riverside Electric System
Number of Meters

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Domestic	100,505	100,054	99,731	99,226	98,930
Commercial	12,245	12,026	11,922	11,817	11,598
Industrial	637	622	625	616	581
Other	49	49	50	52	52
Total – all classes	113,436	112,751	112,328	111,711	111,161

Table 7
Riverside Electric System
Energy Sold
(Millions of kWh)

	Fiscal Year Ended June 30,				
	2024	**2023**	**2022**	**2021**	**2020**
Domestic	710	786	759	783	723
Commercial	427	440	443	430	442
Industrial	916	920	923	891	931
Other	12	15	19	18	18
Wholesale Sales	0	14	2	0	1
Total kWh Sold (1)	2,065	2,175	2,146	2,122	2,115

(1) The difference between the total kWh generated and purchased and the total kWh sold is due to transmission and/or distribution system losses.

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Customer Concentration

The following table lists the Riverside Electric System's top 10 customers for Fiscal Year 2023-24 by dollar amounts charged.

TABLE 8
Riverside Electric System
Top 10 Electric SYSTEM Customers
Fiscal Year 2023-24[(1)]
(Dollars in Thousands)

Electric System Customer	*Electric Charges*[(2)]	*Percent of Electric System Retail Revenues*[(2)]
Local University	$ 14,114,348	4.00%
Local Government	8,530,192	2.42%
Local Government	8,338,317	2.37%
School District	5,164,237	1.47%
Corporation	4,710,601	1.34%
Corporation	4,314,135	1.22%
Corporation	4,177,204	1.19%
Hospital	3,811,163	1.08%
Local University	3,077,010	0.87%
Corporation	3,076,416	0.87%
Total	$ 59,313,623	16.83%

(1) Figures above do not include public benefit surcharge of 2.85% pursuant to AB 1890.
(2) Based on unaudited actual figures.
Source: City.

The City has a strong and diverse customer base with minimal exposure to customer concentration. Many of the Riverside Electric System's industrial customers have loads under 500 kW. The Riverside Electric System's ten largest customers provided approximately 16.83% of retail revenues of $352.5 million for the Fiscal Year ended June 30, 2024, based on unaudited actual figures.

Electric Rates and Charges

Riverside is obligated by its City Charter and by the resolutions under which it has issued its Electric System Revenue Bonds to establish rates and collect charges in an amount sufficient to meet its operation and maintenance expenses and debt service requirements, with specified requirements as to priority and coverage. Electric rates are established by the Riverside Board and approved by the Riverside City Council. Electric rates are not subject to the general regulatory jurisdiction of the California Public Utilities Commission ("CPUC") or any other state agency. The California Public Utilities Code contains certain provisions affecting all municipal utilities such as Riverside, including provisions for a public benefits charge under Assembly Bill 1890 ("AB 1890"). At this time, neither the CPUC nor any regulatory authority of the state nor FERC approves Riverside's retail electric rates, although FERC does approve Riverside's TRR included in the Transmission Access Charge collected from users of the CAISO transmission grid.

Although its rates are not subject to approval by any federal agency, Riverside is subject to certain ratemaking provisions of the federal Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA requires state regulatory authorities and nonregulated electric utilities, including Riverside, to consider certain ratemaking standards and to make certain determinations in connection therewith. Riverside believes that it is operating in compliance with PURPA.

In January 1998, Riverside began collecting a surcharge for public benefit programs on customer utility bills. This surcharge was mandated by State legislation (*i.e.*, AB 1890 and subsequent legislation) and is restricted to various socially beneficial programs and services.

As of January 1, 2024, the Riverside Electric System has 19 rate schedules in effect. Riverside does not provide free electric service.

A rate proposal was provided to the Board on June 12, 2023 and to the City Council on June 27, 2023, after the completion of a rate study dated June 9, 2023 by an independent third party consultant (the "Rate Study"). In July and August 2023, staff conducted a comprehensive community outreach effort to present and obtain feedback on the rate plan proposal. Outreach efforts included various community meetings hosted by Riverside as well as Riverside's attendance at multiple neighborhood and business group meetings. After holding the required public hearing on August 28, 2023, the Board adopted and recommended that the City Council approve a five-year electric rate plan (the "2023 Rate Plan") based on the Rate Study.

On September 19, 2023, the City Council adopted the 2023 Rate Plan, which includes rate increases that became effective on January 1, 2024, and are scheduled for each January 1 thereafter through January 1, 2028, inclusive. The system average rate increase that became effective January 1, 2024 was 7.0%, and will be followed by system average rate increases of 7.0%, 7.0%, 2.0%, and 2.0%, scheduled to become effective on January 1, 2025, 2026, 2027, and 2028, respectively. Actual increases for individual customers will vary by customer class and usage level.

Historically, electric rates for Riverside's customers have been lower than rates for SCE customers. Based on Riverside's rates effective June 1, 2024, Riverside's single-family residential customers with annual monthly average consumption of 600 kWh would pay an average of 77% higher rates if served by SCE (based on average SCE rates). Riverside cannot predict future rate actions with respect to SCE or other utilities.

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The following table sets forth the average billing price per kWh for the various customer classes during the five Fiscal Years shown.

Table 9
Riverside Electric System
Average Billing Price (Cents) Per Kilowatt-Hour(1)
(Retail Sales)

	Fiscal Year Ended June 30,				
	2024	2023	2022	2021	2020
Residential	19.58	17.88	17.70	17.00	16.80
Commercial	18.23	17.53	17.10	17.00	16.60
Industrial	14.16	13.54	13.30	12.60	12.10
Other	44.13	35.78	26.50	26.70	26.50
System Averages	17.07	16.08	15.80	15.20	14.70

(1) Figures above do not include public benefit surcharge of 2.85% pursuant to AB 1890.

Billings and Collections

Electric System service charges are billed and collected on a monthly Statement of Municipal Services and combined with the charges of the City's water, sewer and refuse utilities. The customer service, billing and collection operations are provided for all utilities by designated functions of the City's Public Utilities, Public Works, Finance and Information Technology Departments, coordinated through RPU.

Bills are due and payable on presentation and become delinquent after 21 days. Although the City is not subject to the jurisdiction of the CPUC or other agencies, collection activities for the City substantially conform to the requirements of California Public Utilities Code Section 10010 and California Health and Safety Code Section 116908. Accounts that have not paid their bills by the delinquency date receive an urgent notice providing an additional 10 days to pay. If no payment is received, a notice is delivered by Utility Field Service staff 10 days prior to proposed discontinuance of service, and the customer is charged a $21.50 notification fee. If payment is not received after 60 days, metered service (water and/or electric) may be turned off approximately 1 to 5 working days later. Before service is reinstated, the customer must pay the delinquent amount and a reconnection fee ranging between $43.00 and $80.50, and may be required to pay a customer deposit.

RPU manages delinquencies of amounts billed for the City's Electric System and water, sewer and refuse utilities. Delinquencies from inactive accounts are turned over to a collection agency 90 days after account closure/no activity.

Transfers to the General Fund of the City

Effective December 1, 1977, transfers to the General Fund of the City of surplus funds of the Electric System (after payment of Operating and Maintenance Expenses and debt service on Bonds) are limited by Article XII of the City Charter, as approved by the voters and adopted by the City Council on November 15, 1977. Such transfers are limited to 12 equal monthly installments during each Fiscal Year constituting a total amount not to exceed 11.5% of the Gross Operating Revenues, exclusive of any surcharges, for the last Fiscal Year ended and reported by an independent public auditor. The General Fund transfer is funded through the existing rate plan, thus requiring no additional rate adjustments.

The transfers to the General Fund of the City for Fiscal Years 2022-23 and 2023-24 were $42.3 million and $45.3 million, respectively.

See the caption "—Litigation" for a description of a recent court ruling holding that the General Fund transfer from the Electric System is not a cost of providing the service of the Electric System and violates Article XIIIC of the State Constitution. In response to the ruling, the City Council placed a ballot measure, known as Measure C, on the November 2, 2021 ballot, seeking the approval of City voters to continue transfers of surplus Electric System revenues to the General Fund. Measure C was approved by City voters and the City intends to continue to transfer Electric System revenues to the General Fund.

Unrestricted Cash Reserves

On March 22, 2016, the City Council adopted the Riverside Public Utilities Cash Reserve Policy, which provided a defined level of unrestricted, undesignated and designated cash reserves in the Electric System for strategic purposes. On September 7, 2021, the Cash Reserve Policy was updated and approved by City Council to reflect updates to the designated decommissioning reserve for SONGS, minimum and maximum funding levels for undesignated reserve and other minor revisions. On August 6, 2024, the Cash Reserve Policy was updated and approved by City Council to reduce the annual funding to the San Onofre Nuclear Generating Station Additional Decommissioning Liability Reserve. This policy sets target minimum and maximum levels for the undesignated reserve to mitigate risk in the following categories: operations and maintenance, rate stabilization, capital expenditures and debt service. The undesignated reserve can be used for any lawful purpose and has not been designated for specific capital and operating purposes.

On February 1, 2022, Riverside entered into the $35,000,000 Revolving Credit Facility, which provides additional flexibility and operating liquidity for the Electric System.

As of June 30, 2024, the undesignated Electric System reserve balance was $136.0 million, which, combined with the amount available under the Revolving Credit Facility, was within the minimum and maximum guidelines as set forth in the policy.

Designated reserves are considered unrestricted assets and represent the portion of unrestricted reserves set aside for specific purposes determined by the Board and City Council. Designated reserves may be held for capital or operating purposes. Based on unaudited actual figures, the designated cash reserve balances as of June 30, 2024, are as follows (in thousands of dollars):

Additional Decommissioning Liability Reserve	$10,885
Customer Deposits	5,014
Capital Repair and Replacement Reserve	2,336
Electric Reliability Reserve	95,689
Mission Square Improvement Reserve	2,757
Dark Fiber Reserve	5,556
Total(1)	$122,237

(1) Reflects preliminary unaudited actual figures; subject to change. Final figures will be included as a component of unrestricted cash and cash equivalents in the Statements of Net Position in the Electric System's audited financial statements for the Fiscal Year ended June 30, 2024.

Indebtedness; Joint Powers Agency Obligations

As of December 1, 2024, Riverside had outstanding approximately $582.7 million aggregate principal amount of Electric System Revenue Bonds, which are payable from and secured by a pledge of and lien on net operating revenues of the Electric System, consisting of:

Table 10
Riverside Electric System
Outstanding Electric System Revenue Bonds
As of December 1, 2024

Issue	Principal Amount Outstanding
Electric Revenue Bonds, Issue of 2010A (Federally Taxable Build America Bonds – Direct Payment)	$120,805,000
Refunding Electric Revenue Bonds, Issue of 2019A	218,635,000
Refunding Electric Revenue Bonds, Issue of 2023A	30,400,000
Electric Revenue Bonds, Issue of 2024A	212,835,000
Total	$582,675,000

For the Fiscal Year ended June 30, 2024, Riverside's annual debt service on the outstanding Electric System Revenue Bonds totaled approximately $36.5 million. Assuming no further debt issuances, the annual debt service on such outstanding Electric System Revenue Bonds following June 30, 2024 will be at a high of approximately $51.5 million in 2040, declining to a low of approximately $11.7 million in 2050.

In addition, Riverside participates in certain contracts with Intermountain Power Agency ("IPA") and the Authority. Obligations of Riverside under the agreements with IPA and the Authority constitute operating and maintenance expenses of Riverside payable prior to any of the payments required to be made on the Electric System Revenue Bonds and any parity debt. Agreements between Riverside and IPA and Riverside and the Authority are on a "take-or-pay" basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements contain "step-up" provisions obligating Riverside to pay a share of the obligations of a defaulting participant. Any "step-up" obligation relating to Riverside's participation in transmission projects that it would be responsible for would be included in Riverside's TRR (that would require filing a new TRR at the FERC) and would be recovered from all CAISO grid users. Riverside's participation and share of principal obligation (without giving effect to any "step-up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table. As of June 30, 2024, the City's total debt service obligations with respect to joint powers agency bonds were approximately $58.0 million. In certain cases, Riverside could become responsible for a greater share of debt service on joint powers agency bonds if other participants were to default on their respective obligations with respect to such bonds.

Table 11
Riverside Electric System
Outstanding Debt of Joint Powers Agencies
As of December 1, 2024

	Principal Amount of Outstanding Debt	Riverside Participation[1]	Riverside Share of Principal Amount of Outstanding Debt
Intermountain Power Agency			
Intermountain Power Project[2][3]	$	7.617%	$
Southern California Public Power Authority			
Southern Transmission System[4]	89,480,000	10.164	9,094,747
Total	$		$

(1) Participation obligation is subject to increase upon default of another project participant.
(2) Includes bonds, commercial paper, subordinate notes and line of credit.
(3) The IPP Contract expires in 2027, after which time, Riverside will have no further obligations to pay IPA debt.
(4) The STS Contract expires in 2027, after which time, Riverside will have no further obligations to pay STS debt.

Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In addition, swap agreements entered into by the joint powers agencies are subject to early termination under certain circumstances, in which event substantial payments could be required to be made to the applicable swap provider.

Insurance

The City's Risk Management Division manages the insurance needs of the City's Electric System. The City's Self-Insurance Trust Fund Reserve Policy requires that both the Liability and Worker's Compensation funds maintain cash on hand in the minimum amount equal to 50% of all outstanding claims. The fund balance amounts are based on annual actuarial studies on the City's automobile, general, and worker's compensation liability and internal claim data. The actuarial reports are issued by an outside firm.

The City carries multiple General Liability policies: a primary liability policy and three excess liability policies. The primary General Liability policy provides the City with $4,000,000 in total aggregate limits and the excess General Liability policies provide the City with $21,000,000 in coverage, for a total of $25,000,000 in combined General Liability coverage. Both the primary and excess General Liability policies cover general and automobile liability claims, including but not limited to Law Enforcement Liability and Public Officials Errors and Omissions coverage. The City also purchases an excess Workers Compensation policy with an aggregate limit of $25,000,000. Both the General Liability and Worker's Compensation programs have self-insured retentions of $3,000,000. A self-insured retention is the dollar amount that the City must pay before an insurance policy responds to a loss.

The City participates in two separate property insurance programs; the first is an "All Risk" property program that affords an aggregate limit of $1 billion for City-owned properties, and the second program provides $210 million in property and equipment breakdown coverage for RERC, Springs and Clearwater. The City also purchases a stand-alone Pollution policy for RERC, Springs and Clearwater. See the caption "—City-Owned Generating Facilities" for a discussion of RERC, Springs and Clearwater. The City's property deductibles range from between $100,000 to $250,000 depending on the peril at the time of loss. At the time of loss, valuation will be on a replacement cost basis with actual loss sustained for time element coverages and an actual cash value for all City-owned equipment.

The City does not currently maintain earthquake insurance on the Electric System's facilities.

Litigation

Parada II. On September 12, 2018, a petition for writ of mandate entitled *Parada v. City of Riverside* (Parada II) was filed against Riverside seeking to invalidate, rescind and void under Proposition 26 the Electric System's rates approved by City Council on May 22, 2018, which took effect on January 1, 2019, by challenging the portion of the electric rates that are attributable to the General Fund transfer.

On October 9, 2020, the court ruled that the General Fund transfer from the Electric System is not a cost of providing the service of the Electric System and violates Article XIIIC of the California Constitution. Based on the court's order in the liability phase of the trial, Riverside estimated that approximately $19 million-$32 million of the General Fund transfer was potentially attributable to Electric System revenue that was not approved by the voters and could be subject to refund.

On May 17, 2021, Riverside and the plaintiffs entered into a settlement agreement that was conditioned on: (1) the City Council's placement of a ballot measure in the November 2021 election to approve the General Fund transfer as a general tax (the "Ballot Measure"); and (2) voter approval of the Ballot Measure. The City Council placed the Ballot Measure on the ballot for the November 2, 2021 election. The parties agreed to stay the litigation until certification of the results of the Ballot Measure. If voters approved the Ballot Measure, Riverside agreed to refund to Electric System customers an amount equal to $24 million less the amount awarded to the plaintiffs' counsel in fees, paid over a five year period that was to begin no later than February 1, 2022. If voters did not approve the Ballot Measure, the litigation would then resume.

On or about September 16, 2021, prior to the November 2, 2021 election, a petition for writ of mandate entitled *Riversiders Against Increased Taxes v. City of Riverside, et al.* (the "RAIT lawsuit") was filed against Riverside challenging the Ballot Measure on the grounds that it could not be adopted at the November 2021 election because that election is a "special" election and, under Proposition 218, a ballot measure to impose a general tax can only be submitted to voters at a general election. On November 9, 2021, the court set a trial date for the RAIT lawsuit for January 7, 2022 and ordered a stay of the certification of the Ballot Measure election results pending the January 7, 2022 hearing. The court did not otherwise delay or cancel the election for the Ballot Measure, and the election was held on November 2, 2021, with Measure C approved by a majority of the voters.

On April 26, 2022 the RAIT lawsuit trial court determined that the November 2021 election was a "special election" rather than a "general election" and therefore did not comply with Proposition 218. The court further ruled that it lacked power to enjoin the certification of election results or to otherwise invalidate the election. Both sides have since appealed the April 26, 2022 ruling. On July 25, 2024, the appellate ruled in favor of Riverside and against RAIT, holding that Riverside conducted a proper election in compliance with Proposition 218 and 26. RAIT petitioned for review by the California Supreme Court. On October 30, 2024 the California Supreme Court denied the petition for review.

On May 12, 2022, the City and the plaintiffs in the Parada II lawsuit amended the May 17, 2021 conditional settlement agreement to reflect the following additional terms: (a) Riverside agreed to start making refunds to ratepayers by October 1, 2022; (b) if Riverside prevailed in the appeal of the trial court's decision in the RAIT lawsuit, no additional refunds would be due to the ratepayers; (c) if Riverside did not prevail in the appeal of the trial court's decision in the RAIT lawsuit, additional refunds would be implemented in the amount of $705,882 per month, from November 2021 until: (i) Riverside set new electric rates; (ii) voters approve a valid ballot measure relating to the General Fund transfer; or (iii) Riverside otherwise stops collecting the General Fund transfer from the Electric System. The Parada II lawsuit was dismissed on May 13, 2022. The RAIT lawsuit plaintiffs sought to intervene in the Parada II lawsuit and set aside this dismissal. However, on August 3, 2022, the Parada II trial court refused to set aside the dismissal.

The City Council adopted a resolution certifying the results of the Measure C election on July 19, 2022. Riverside has now begun to implement the settlement agreement with the Parada II plaintiffs. However, because the appellate court ruled in favor of the City, no additional refunds are owed to ratepayers by the City.

Pending lawsuits and other claims against Riverside with respect to the Electric System are incidental to the ordinary course of operations of the Electric System and are largely covered by Riverside's self-insurance program. In the opinion of the Electric System's management and the City Attorney, such lawsuits (including the lawsuits discussed above) and claims will not have a materially adverse effect upon the financial position of the Electric System.

Summary of Operations

The following table prepared by Riverside shows the Net Operating Revenues of the Electric System for the five full Fiscal Years shown. The information shown is based on the audited financial statements of the City's Electric System for such periods as well as preliminary unaudited results for Fiscal Year 2023-24, but excludes certain receipts which do not constitute Gross Operating Revenues and certain non-cash items and reflects certain other adjustments.

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Table 12
Riverside Electric System
Summary of Operations and Debt Service Coverage
($000's)

	Fiscal Year Ended June 30,				
	2024*	2023	2022	2021	2020
Operating Revenues[1]:					
Residential	$138,879	$140,538	$134,403	$133,460	$121,162
Commercial, Industrial and Other	213,623	206,953	203,474	188,947	189,552
Wholesale Sales	0	2,043[2]	89	27	0
Transmission Revenues	39,934	35,233	32,245	32,316	34,817
Other	26,089	24,403	18,758	12,099	13,960
Total Operating Revenues Before (Reserve)/Recovery	418,525	409,170	388,969	366,849	359,491
Reserve for Uncollectible, Net of (Reserve)/Recovery	(2,466)	(475)	681	(4,034)	(1,891)
Total Operating Revenues, Net of (Reserve)/Recovery	416,059	408,695	389,650	362,815	357,600
Interest Income/(Loss) [3]	11,782	7,874	4,461	4,794	9,439
Capital Contributions	4,701	4,951	5,445	3,456	4,875
Non-Operating Revenues	4,024	6,343	7,094	6,897	1,885
Total Revenues	$436,566	$427,863[4]	$406,650[4]	$377,962	$373,799
Operating and Maintenance Expenses[5][6]:					
Nuclear Production[7]	955	1,023	914	822	1,642
Production & Purchased Power[8]	198,611[9]	194,891[9]	175,682	163,086	155,898
Transmission Expenses[10]	54,248	68,052	65,996	59,770	58,830
Distribution Expenses	18,001	21,415	18,270	21,735	17,665
Customer Account Expenses	7,760	7,871	6,845	6,829	6,832
Customer Service Expenses	2,310	2,182	1,727	1,638	713
Administration & General Expenses[11]	23,812	18,908[12]	10,992[13]	12,046	16,120
Clearing & Miscellaneous Expenses	20,945	18,559	17,794	18,367	19,362
Total Operating and Maintenance Expenses	$326,642	$332,901	$298,220	$284,293	$277,062
Net Operating Revenues Available for Debt Service and Depreciation	$109,924	$94,962	$108,430	$93,669	$96,737
Debt Service Requirements on Electric System Revenue Bonds[14]	$50,694	$46,400	$46,028	$44,923	$38,633
Debt Service Coverage Ratio	2.17x	2.05x	2.36x	2.09x	2.50x

* Reflects preliminary unaudited results; subject to change.
(1) Operating Revenues exclude restricted revenues generated from the public benefits charge under AB 1890.
(2) Increase in Fiscal Year 2022-23 reflects a transmission constraint, requiring the power that the City was scheduled to receive to be resold.
(3) Differs from audited financial statements because the above numbers exclude unrealized losses (and gains), consisting of market value adjustments to Electric System investments in accordance with GASB Statement No. 31, of $(4,593), $4,298, $14,791, $1,922 and $(6,933) in Fiscal Years 2019-20 through 2023-24, respectively.
(4) Includes net revenue adjustments of $134, $247 and $304 under GASB Statement No. 87 relating to leases for Fiscal Years 2021-22 through 2023-24, respectively. The City elected not to revise the beginning net position upon its adoption of GASB Statement No. 87 as of July 1, 2021.
(5) Operating and Maintenance Expenses exclude expenses incurred under the related program.
(FOOTNOTES CONTINUED ON FOLLOWING PAGE)

(6) In accordance with City Resolution No. 17662, as amended and supplemented, the figures shown exclude contributions to City's General Fund of $39,558, $39,899, $39,436, $42,326 and $45,289 for Fiscal Years 2019-20 through 2023-24, respectively. Also excludes depreciation and amortization.

(7) Nuclear Production reflects non-decommissioning expenses and changes to decommissioning liability related to SONGS.

(8) Includes fuel expense for City-owned generating facilities and payments to IPA and the Authority, other than payments relating to transmission projects with the Authority (Southern Transmission System, Mead-Phoenix, and Mead-Adelanto).

(9) Increase in Fiscal Year 2022-23 primarily due to exceptionally elevated winter natural gas prices, which in turn caused significantly elevated power prices. Such power prices were already higher due to the Ukraine/Russia war which commenced in early 2022, which caused price disturbances in both the gas and power markets. Increase in Fiscal Year 2023-24 due to fuel restrictions on our Intermountain Power Project coal resource throughout the fiscal year that forced the utility to forward hedge significantly more energy.

(10) Includes payments relating to transmission projects with the Authority (Southern Transmission System, Mead-Phoenix and Mead-Adelanto).

(11) Excludes Governmental Accounting Standards Board ("GASB") Statement No. 68, Accounting and Financial Reporting for Pension non-cash adjustments of $3,364, $9,682, $(16,425), $(1,308) and $7,707 for Fiscal Years 2019-20 through 2023-24, respectively. Excludes GASB Statement No. 75, Accounting and Financial Reporting for Post-Employment Benefits Other Than Pensions non-cash adjustments of $490, $183, $530, $431 and $474 for Fiscal Years 2019-20 through 2023-24, respectively.

(12) Increase reflects one-time employee stipend (not qualifying for the purpose of pension compensation) approved by the City Council on September 20, 2022.

(13) Decrease reflects non-cash pension accounting standard adjustment.

(14) Includes debt service on a portion of the City's pension obligation bonds issued in June 2020 that is attributable to the Electric System. Notwithstanding the inclusion of debt service in the table, such amounts are payable from moneys remaining after payment of Electric System Revenue Bonds.

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The following Statements of Net Position have been prepared by Riverside for the five full Fiscal Years shown. The information for the Fiscal Years ended June 30, 2020 through June 30, 2023 is based on the audited financial statements of the City's Electric System for such periods. The information for the Fiscal Year ended June 30, 2024 is based on the preliminary, unaudited financial statements.

Table 13
Riverside Electric System
Electric Statements of Net Position ($000)

	Fiscal Year Ended June 30,				
	2024*	2023	2022	2021	2020
Assets and Deferred Outflows of Resources					
Utility plant					
Production	$265,966	$265,966	$269,814	$269,248	$268,088
Transmission	53,590	53,416	50,417	49,079	45,084
Distribution	752,595	741,877	725,159	706,807	680,961
General	124,700	122,127	123,432	117,696	114,519
Intangible	27,277	26,667	25,963	21,986	21,986
	1,224,128	1,210,053	1,194,785	1,164,816	1,130,638
Less accumulated depreciation	(599,984)	(564,436)	(535,466)	(503,088)	(468,791)
	624,144	645,617	659,319	661,728	661,847
Land	56,435	56,386	53,042	53,042	53,032
Intangible, non-depreciating	10,651	10,651	10,651	10,651	10,651
Construction in progress	85,233	72,262	72,724	72,481	64,968
Total utility plant	776,463	784,916	795,736	797,902	790,498
Lease and subscription assets[6]	844	721	628	0	0
Less lease and subscription accumulated amortization[6]	(434)	(316)	(137)	0	0
Total capital assets	776,873	785,321	796,227	797,902	790,498
Restricted assets[1]	140,025	133,151	118,828	125,738	154,590
Current assets:					
Cash and investments[2]	258,200	247,831	274,172	287,294	299,734
Accounts receivable, net	41,805	37,260	50,093	43,785	41,851
Advances to other funds of the City	0	0	0	0	0
Accrued interest receivable	1,626	1,033	663	586	881
Leases receivable[6]	1,343	1,359	990	0	0
Inventory	1,464	1,464	485	971	971

Prepaid expenses	3,859	6,168	6,127	6,964	6,433
Unamortized purchased power	664	666	653	644	634
Total restricted and current assets	448,986	428,932	452,011	465,982	505,094
Other non-current assets:					
Advances to other funds of the City	1,555	2,003	2,454	2,925	3,383
Lease receivable[6]	11,069	10,407	7,099	0	0
Net Pension Asset	0	0	26,219	0	0
Unamortized purchased power	11,025	11,664	12,317	12,971	13,611
Regulatory assets[3]	2,109	1,573	1,665	1,757	1,850
Total other non-current assets	25,758	25,647	49,754	17,653	18,844
Deferred outflows of resources:					
Deferred outflows related to pension[5]............	31,018	34,931	9,168	15,820	83,568
Deferred outflows related to other post-employment benefits............	1,498	1,592	1,805	2,167	1,601
Changes in derivative values[8]	0	1,571	5,924	16,228	22,623
Loss on refunding	2,155	7,530	8,046	8,567	9,091
Total deferred outflows of resources............	34,671	45,624	24,943	42,782	116,883
Total assets and deferred outflows of resources	$1,414,031	$1,285,524	$1,322,935	$1,324,319	$1,431,319

Net Position, Liabilities and Deferred Inflows of Resources					
Net position:					
Net investment in capital assets[9]	$230,789	$254,224	$246,097	$237,501	$238,347
Restricted for debt service	23,981	19,332	18,967	18,615	18,286
Restricted for regulatory requirements	34,261	25,502	19,598	16,923	16,815
Restricted for unfunded accrued liability[7]	3,510	0	0	0	0
Restricted for public benefit programs	32,482	29,329	25,857	22,346	19,514
Unrestricted[9]	183,511	174,965	195,044	201,988	221,923
Total net position	508,534	503,352	505,563	497,373	514,885
Long-term obligations, less current portion	712,106	590,602	615,834	639,791	662,290
Total net position and long-term obligations............	1,220,640	1,093,954	1,121,397	1,137,164	1,177,175
Non-current liabilities:					
Compensated absences........	2,065	1,889	2,426	3,389	1,227
Nuclear decommissioning.	33,838	38,646	44,497	43,642	49,529
Other postemployment benefits liability/ payable	10,049	9,420	10,066	11,126	10,708
Net pension liability[4]	44,227	38,748	0	39,233	89,792
Derivative instruments[8]............	0	4,097	8,905	19,968	27,451

Regulatory liability[8]	0	4,675	4,220	3,461	2,373
Lease liability[5]	162	225	363	0	0
SBITA liability[5]	46	7	0	0	0
Total non-current liabilities	90,387	97,707	70,477	120,819	181,080
Current liabilities payable from restricted assets:					
Accrued interest payable	9,816	5,083	5,465	4,085	5,872
Nuclear decommissioning	12,244	10,227	8,813	7,254	6,179
Public benefit programs payable	750	866	624	239	304
Current portion of long-term obligations	23,680	22,633	20,992	19,345	17,370
Total current liabilities payable from restricted assets	46,490	38,809	35,894	30,923	29,725
Current liabilities:					
Accounts payable and other accrual	26,621	25,173	27,860	22,476	24,519
Unearned revenue	762	314	1,412	67	73
Customer deposits	12,881	11,734	11,888	10,563	9,265
Other postemployment benefits liability/payable[6]	397	417	394	0	0
Lease liability[5]	132	137	134	0	0
SBITA liability[5]	50	42	0	0	0
Total current liabilities	40,843	37,817	41,688	33,106	33,857
Deferred inflows of resources:					
Deferred inflows related to pension	1,892	3,577	44,089	1,714	9,220
Deferred inflows related to other postemployment benefits	2,038	2,266	1,426	593	262
Lease related items[5]	11,741	11,394	7,964	0	0
Total deferred inflows of resources	15,671	17,237	53,479	2,307	9,482
Total net position, liabilities and deferred inflows of resources	$1,414,031	$1,285,524	$1,322,935	$1,324,319	$1,431,319

* Reflects preliminary unaudited results; subject to change.
(1) Includes current and non-current restricted assets for historical comparison purposes.
(2) See discussion under "Unrestricted Cash Reserves" above.
(3) Riverside elected to record debt issuance costs and replacement power costs as regulatory assets which allows for deferring these expenses to be reflected in future rates.
(4) Decrease from Fiscal Years 2019-20 to 2020-21 primarily due to the payment outflow of the 2020 Pension Obligation Bond Series A and the resulting decrease in net pension liability from the payment.
(5) Creation of these assets and liabilities resulted from the implementation of GASB Statement No. 87 *Leases* in the Fiscal Year ended June 30, 2022 and GASB Statement No. 96 *Subscription-Based Information Technology Arrangements* in the Fiscal Year ended June 30, 2023.
(6) For Fiscal Years 2019-20 through 2020-21, current other postemployment benefits liability/payable is included in the non-current liabilities portion.
(7) Reflects restricted cash and investments held at fiscal agent for moneys held for the future payment of pension related costs.
(8) Decrease in fiscal year 2023-24 due to the refunding from the 2023 and 2024 Electric Revenue Series A bond issuances. The Electric System no longer has any variable rate debt.
(9) Fiscal years 2019-20 to 2022-23 have been restated to remove retainage payable from the calculation of Net Investment in Capital Assets.

Electric System Strategic Plan

Strategic Plan. The Riverside Board and City Council have had a formal strategic plan in place with respect to the Electric System since 2001, including the adoption of the following mission statement: "The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community."

Through strategic planning process and workshops, long-term goals and objectives have been established by the Riverside Board to provide the framework to implement the Riverside Public Utilities Department's Mission Statement. The current Ten-Year Goals adopted by the Riverside Board are (not in priority order):

- Employ state-of-the-art technology to maximize reliability and customer service;
- Foster economic development and job growth in the City of Riverside;
- Communicate effectively the accomplishments, challenges and opportunities for the full utilization of electric and water resources;
- Develop fully low-cost, sustainable, reliable electric and water resources; and
- Enhance the effective and efficient operation of all areas of the utility.

Three-Year Goals and Strategic Plan Objectives are also established to ensure the achievement of these long-term goals, and these are (not in priority order):

- Contribute to the City of Riverside's economic development while preserving Riverside Public Utilities' financial strength;
- Maximize the use of technology to improve utility operations;
- Impact positively legislation and regulations at all levels of government;
- Develop and implement electric and water resource plans; and
- Create and implement a workforce development plan.

In 2015, management engaged the community, Riverside Board and City Council through a series of meetings and workshops to create a Utility 2.0 Strategic Plan that provides the vision, changes and actions required to thrive as a Utility of the future. The Utility 2.0 Strategic Plan was designed to facilitate and advance the strategic goals adopted by the City Council in the Riverside 2.0 Strategic Plan as well as the strategic goals of the Riverside Board. Areas of focus for Utility 2.0 include infrastructure improvement, workforce development, utilizing advanced technology and thriving financially, which have been developed through a number of roadmaps. In October 2015, conceptual approval was given by the Riverside Board and City Council to implement the Utility 2.0 Strategic Plan.

The Thriving Financially Roadmap reviewed the areas of rates, reserves, debt and other related policies to ensure the financial balance of Riverside Public Utilities. Rates, cash reserves, debt and other revenue sources were evaluated together with the development of a 10-year pro-forma (financial plan). Several dependent projects were completed during the development of the 10-year pro-forma and rate plan. These projects include the update and approval of the reserve policy, development and approval of an overall fiscal policy, and development and approval of electric and water cost of service studies.

An overall fiscal policy, including a comprehensive section on cash reserves, was completed and adopted by the City Council in July 2016 and subsequently updated and approved by City Council in September 2021, and again in August 2024. The electric and water 10-year pro-forma, cost of service and rate design studies were completed and presented to the City Council in September 2023. The Riverside Public Utilities Department recommended a redesign of its rates over a five-year period to better align with its cost of serving customers and its revenue requirement. The electric rate restructuring is designed to provide financial stability to support the Electric System's efforts to sustainably improve infrastructure reliability, meet renewable energy and energy efficiency goals, follow legal and regulatory requirements and correct the imbalance of costs versus revenue recovery. Rates have been designed to provide a transition to reflect the nature of underlying costs while encouraging the expansion of customer solar and other distributed generation.

Operating Initiatives and Reserves. Riverside's retail revenues increased by approximately 13.4% from Fiscal Years ended June 30, 2020 to June 30, 2024 primarily as a result of rate plan increases. Historically, retail revenues have generally increased year over year due to annual increases in retail rates. Operating and maintenance expenses (excluding depreciation and public benefit programs) increased by approximately 19.2% from Fiscal Years ended June 30, 2020 to June 30, 2024 due to higher power costs, transmission charges and other miscellaneous operating costs. Positive operating results over time have contributed to improving the City's reserve requirements and the overall goal to continue to be fiscally sound. (See "Unrestricted Cash Reserves.")

Sustainability Initiatives. Riverside has a long history of valuing sustainability and ensuring economic development. Recent efforts for sustainability began in 2001 when Riverside began using light-emitting diodes ("LED") in all City traffic signals to reduce electricity usage. Today, Riverside remains committed to environmental issues and serves as a state leader in sustainability.

Riverside's first sustainability policy statement was adopted in 2007 and ultimately led to the adoption of three Green Action Plans, the latest of which was adopted in 2012. Most recently, the City adopted the Envision Riverside 2025 Strategic Plan in October 2020. This plan incorporates sustainability throughout as a cross cutting value and environmental stewardship as one of six priority areas for Riverside. Additional adopted policies can be found in the City's General Plan 2025 (2007), the Environmentally Preferable Purchasing Policy (2009), the Food and Agriculture Policy Action Plan (2015) and the Riverside Restorative Growthprint (2016). The City is in the process of adopting a new General Plan (GP) and Climate Action and Adaption Plan (CAAP). Once these documents are completed, they will serve in place of the previous Green Action Plans and Riverside Restorative Growthprint.

The City hosts community-wide Green Riverside Leadership Summits. Since 2012, summits have been held every 2 to 3 years. Events in 2012 and 2019 were in partnership with the University of California Riverside. Events in 2014 and 2016 were conducted as part of the community-led Riverside Green Festival and Summit.

Riverside has received numerous recognitions for its sustainability programs and initiatives. In 2009, the California Department of Conservation named Riverside its first "Emerald City" in recognition of its sustainable green initiatives and commitment to help the state achieve multiple state environmental priorities. Riverside was honored in 2016 with the Green Community Award from Audubon International, recognizing the City for its ongoing sustainability initiatives. In addition, Riverside received the 2016 Sustainable Communities Award from the Green California Leadership Summit for its ongoing community-wide sustainability projects and programs that create environmental awareness and action throughout the community, including business, government and private citizens. The Green California Leadership Summit again recognized Riverside in 2018 with its Leadership Award for the City Green Fleet Program. Additionally, in 2022, Riverside was ranked #1 in North America for the Green Fleet Award by the NAFA Fleet Management Association.

Riverside initiated an ambitious LED streetlight replacement program in 2016. The program will eventually replace all City-owned streetlights, resulting in approximately 10 million kWh saved annually along with substantially reduced maintenance costs. Additionally, the Utility's Energy, Water and Custom Energy technology grant programs continue to encourage local higher education institutions and business electric customers to submit proposals for potential grant funding for important research projects that explore new and innovative ways to advance energy technology.

Economic Development. The Electric System supports the local economy by offering some of the lowest commercial rates in Southern California combined with attractive economic development electric discount rates to qualified new and expanded load customers. These rate programs have helped create and retain over 3,600 jobs in Riverside since 2010. In late 2021, the Electric System relaunched the commercial energy audit program, which provides key account customers with a comprehensive energy efficiency plan, a priority list of recommended energy efficiency measures, an estimated return on investment and applicable utility incentives. To date, several key account customers have utilized this program, which has delivered in excess of 700,000 kWh annual savings so far. Audits for key account customers are in process, with more anticipated in the future.

Beyond rate incentives, the Electric System also offers local businesses a comprehensive assortment of water and energy efficiency programs to improve building efficiency and reduce customer electric consumption. Fiscal Year 2021-22 commercial energy efficiency programs saved a total of 4.2 million kWh. Fiscal Year 2022-23 saw increased energy efficiencies being realized, with almost 7.3 million kWh saved via the Electric System's programs. In fiscal year 2023-24, these numbers increased and 8.1 million kWh of energy savings was made.

All of the above-mentioned efforts support organizations and companies to meet their sustainability goals. Most recently, the State's Air Resources Board relocated their Southern California headquarters to Riverside. The campus opened in 2021 and is one of the largest and most advanced vehicle emissions testing and research facilities in the world. Additionally, the headquarters is LEED Platinum, the highest level awarded by the U.S. Green Building Council for the overall sustainability and energy efficiency of a building. This facility, through a combination of on-site solar PV and a 100% renewable energy rate program through the Electric System, receives all of its power from non-carbon emitting resources.

Power Resource Portfolio Management. Riverside manages long-term fuel and power supply risk, renewable resource procurement and compliance with potential state and federal GHG legislation in an integrated fashion. The 2023 Integrated Resource Plan ("IRP") defines the City's risk based, long-term plan for providing stable and predictable rates for customers through the procurement of new energy supply sources at reasonable prices. Riverside updated its IRP in 2023, and the Board and City Council adopted and approved the IRP on April 8, 2024 and June 11, 2024, respectively. The 2023 IRP provides an impact analysis of the City's acquisition of new power resources, specifically towards meeting the State of California's aggressive carbon reduction goals, and the effect these resources will have on Riverside Public Utilities' future projected power supply costs in the 2024-2025 timeframe. Both resource portfolio and energy market issues are examined in the IRP, including (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives and cash-flow risk metrics, (e) cost effectiveness of Energy Efficiency and Demand Side Management programs with respect to both the City and customers, (f) impacts of various emerging technologies on carbon reduction goals and future cost of service metrics, and (g) minimizing localized air pollutants and GHG emissions in disadvantaged communities within Riverside.

The IRP provides for a future resource portfolio with a higher reliance on renewable resources, especially geothermal resources, utility-scale solar PV and wind resources, City-owned, lower-carbon emitting natural gas generation, battery energy storage and an increased emphasis on energy efficiency and demand-side management programs. Riverside currently owns 265.5 MW of natural gas fired generation; this generation allows the City to meet its local capacity requirement imposed by the CAISO while minimizing environmental impacts and cost exposures. This natural gas generation is comprised of the 29.5 MW Clearwater power plant, four 49 MW LM-6000 peaking power plants at RERC, and four 10 MW super-peaking power plants at Springs Generating Project. The IRP studies battery energy storage resources as the potential replacement option for the Springs Generating Project and RERC when these facilities reach end-of-life.

Since late 2012, Riverside has contracted for a diverse portfolio of renewable resources totaling 239.7 MW under medium and long-term power purchase agreements and power sales agreements. This portfolio of renewable resources consists of 96.0 MW of geothermal resources, 46.3 MW of wind resources, and 97.4 MW of solar PV resources. This portfolio of renewable resources enabled Riverside to significantly exceed the RPS mandate of 33% of the retail electricity energy needs by 2020. Riverside served 46% of its retail energy needs with renewable energy in calendar year 2023 (the most recent calendar year for which such information is available). Riverside has also received approximately 761,000 MWh of Historic Carryover RPS credits from the CEC; these credits can be used along with the energy from the above-mentioned renewable resources to meet the City's post-2020 RPS mandates at least through 2028. Additionally, Riverside has contracted for a 125 MW share of the SunZia Wind Project, which is currently under development and will begin delivering energy in mid-2026, and a current Riverside geothermal contract will begin delivering an additional 20 MW starting in 2027. The additional capacity and renewable energy from these projects will allow Riverside to achieve at least a 60% RPS by 2030 as well as contribute to replacing Riverside's IPP contract when it expires in June 2027.

Federal Policy on Cyber Security

On February 13, 2013, then-President Obama issued an Executive Order entitled "Improving Critical Infrastructure Security" (the "Executive Order"). Among other things, the Executive Order called for improved information sharing and processing of security clearances for owners and operators of critical infrastructure. The 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 (the "Framework") to reduce cyber risks to critical infrastructure. NIST released the first version of the voluntary Framework on February 12, 2014 and finalized the second version of the Framework in April 2018.

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 created an industry-supported, voluntary cyber security information sharing program that encouraged both public and private sector entities to share cyber-related threat information.

The evolution of federal cybersecurity policy since 2015 demonstrates a concerted effort to address the escalating complexity of cyber threats. Early efforts pursued collaboration between the public and private sectors in sharing cyber threat intelligence. Subsequent measures, including Presidential Policy Directive 41 (PPD-41) in 2016, provided a structural framework for coordinating federal agency responses during significant cyber incidents. These initial actions highlighted the importance of defense mechanisms and interagency cooperation in mitigating cyber risks.

In the following years, federal policy evolved to prioritize both proactive and reactive measures. The establishment of the Cybersecurity and Infrastructure Security Agency (CISA) in 2018 institutionalized the protection of critical infrastructure, indicating an essential shift toward recognizing cybersecurity as fundamental to national security. Meanwhile, the Biden administration's Executive Order 14028 in 2021 marked a key moment, mandating zero trust architectures, enhancing software supply chain security, and standardizing incident detection mechanisms across federal agencies. These initiatives were further reinforced by the Cyber Incident Reporting for Critical Infrastructure Act (CIRCIA) in 2022, which emphasized timely reporting of incidents to facilitate coordinated responses.

More recently, the 2023 National Cybersecurity Strategy reflects an advanced approach to addressing emerging threats such as ransomware and supply chains. Federal policies now aim to anticipate risks associated with advanced technologies, such as artificial intelligence (AI), while investing in resilient and secure critical infrastructure.

The City participates in sharing and receiving information about cyber threats through several hubs, including the Electricity Information Sharing and Analysis Center and the National Cybersecurity and Communication Integration Center (NCCIC).

In addition, the federal Energy Policy Act of 2005, other provisions of which are discussed under the caption "—Federal Energy Legislation—Energy Policy Act of 2005" below, gave FERC the authority to oversee the reliability of the bulk power system, including the authority to approve mandatory cyber security reliability standards. The North American Electric Reliability Corporation ("NERC"), which FERC has certified as the nation's Electric Reliability Organization, developed Critical Infrastructure Protection ("CIP") cyber security reliability standards.

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 ("EPAct 2005"), FERC was given refund authority over publicly owned utilities if they sell electrical energy into short-term markets, such as that controlled by the CAISO, 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 (an "ERO") to establish and enforce, under FERC supervision, mandatory reliability standards (the "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 (the "Regional Entities") may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce them. The Western Electricity Coordinating Council is the Regional Entity for the City's region. 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 authorized 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 City) by requiring all such utilities to file Open Access Transmission Tariffs ("OATTs"). Order No. 888 also requires "non-jurisdictional utilities" (such as the City) 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 to 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 its 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 which 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 of EPAct 2005 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 stated 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.

On May 13, 2024, FERC issued Order 1920 to reform the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. Order 1920, among other things, requires public utility (jurisdictional) transmission providers to conduct and periodically update long-term regional transmission planning to anticipate future needs, consider a broad set of benefits when planning new facilities, identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, propose methods of cost allocation to pay for selected long-term regional transmission facilities, and increase transparency regarding local transmission planning information. Order 1920 expands the role of states throughout the process of planning, selecting and determining how to pay for new transmission facilities.

Order 1920 reflects 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 applicable decarbonization goals.

Other Federal Legislation

Legislation is introduced frequently in Congress addressing domestic energy policies and various environmental matters and 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, a federal cap-and-trade program to reduce GHG emissions 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 (such as a federal energy efficiency standard and expedited permitting for natural gas drilling projects), cyber security, reducing regulatory burdens, climate change and water quality. Many of these bills, if enacted into law, could have a material impact on the Electric System and the electric utility industry generally. In light of the variety of issues affecting the electric utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements and cyber security is also possible. The City is unable to predict the outcome or potential impacts of any possible legislation on the City at this time.

Nuclear Regulatory Commission Initiatives

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 or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities. For instance, in the aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, the NRC undertook an independent review of the events at Fukushima Daiichi, including a review of the agency's processes and regulations, in order to determine whether the agency should promulgate additional regulations and possibly make more fundamental changes to the NRC's system of regulation. In addition, various industry organizations developed action plans for American nuclear power plants that are designed to ensure their continued reliability. A task force was formed for PVNGS under the direction of the PVNGS' Chief Nuclear Officer.

The NRC issued regulatory requirements for all 104 operating nuclear reactors located in the United States (including PVNGS) based on the task force's evaluations, which including modifications to operating licenses requiring safety enhancements. A number of improvements have been instituted at PVNGS driven by such requirements and the findings of the task force. Among such improvements are an increase in the redundancy in PVNGS power supply to emergency cooling systems, reinforcement of the spent fuel pool, acceleration of the transfer of spent fuel from the pool to the dry cask storage and added pipelines and associated equipment necessary for supplying additional cooling water to the reactors and the 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.

In the event of noncompliance with its requirements, the NRC has the authority to impose monetary civil penalties or a progressively increased inspection regime that could ultimately result in the shut-down of a unit, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect the Electric System's financial condition, results of operations and cash flows. See the caption "—Entitlements—PVNGS."

Environmental Issues

General. Electric utilities are subject to continuing environmental regulation. Federal, state and local standards and procedures which regulate the environmental impact of electric utilities are subject to change. These changes may arise from new and changing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any Electric System facilities or projects will remain subject to the laws and regulations that are 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 substantially impact current environmental standards and regulations and other matters described herein.

New laws and regulations could be imposed that could impact the City's ability to operate the Electric System or impose significant compliance costs. The inability to comply with environmental standards could result in, for example, additional capital expenditures, reduced operating levels or the shutdown of individual units which are 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 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 ("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. 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 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. In February 2024, the EPA announced that it will remove the elements that would have applied to existing natural gas-fired power plants from the final version of the rule. Instead, the EPA stated that it will commence a new rulemaking process that will apply to existing natural gas-fired plants and regulate additional pollutants. The rule relating to new gas plants and existing coal plants was finalized on April 25, 2024.

The Biden administration's proposed new carbon pollution standards are expected to face legal challenges and the City is unable to predict at this time the outcome of any such challenges. Given the uncertainty regarding such matters, it is too early to determine the effect that any final rules promulgated by the EPA regulating GHG emissions from electric generating units will have on the Electric System.

Inflation Reduction Act. On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 (the "IRA"). The IRA introduces a large amount of funding and grants for governmental and non-profit organizations. Among the most significant energy-related grants are grants for "zero-emissions technologies" and other GHG reduction activities as determined the EPA. Pursuant to the IRA, public power utilities and other tax-exempt entities will also be given access to refundable direct payment tax credits. Among the energy-related tax credits that may be available if certain requirements are met are a clean hydrogen production tax credit, a biogas and energy storage credit and enhancements to the credit for carbon capture. The IRA also expands and extends the renewable electricity production tax credit and the investment tax credits for renewable energy sources.

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, with the goal of improving public health without consideration of cost. When a NAAQS has been established, each state must identify areas within its boundaries 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 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. In 2019, the United States Court of Appeals for the District of Columbia Circuit upheld most of the EPA's 2015 thresholds for ground level-ozone. 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.

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 February 7, 2024, the EPA announced a final rule to strengthen certain NAAQS for fine particulate matter. Areas that are designated as nonattainment areas have planning obligations to demonstrate attainment and meet the new standard within 6 years following the nonattainment designations.

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 (the "MATS"), establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards) and 112 (toxics program) of the Clean Air Act. The MATS rule was 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 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 were to 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 MATS had a minimal impact on the City. 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 MATS rule. On July 17, 2020, the EPA finalized revisions to the electronic reporting requirements for MATS that revised and streamlined reporting and provided enhanced access to MATS data, without imposing new monitoring requirements. In April 2024, the EPA finalized a rule that modified regulation of coal- and oil-fired power plants, including further restricting their emissions and changing emissions monitoring requirements.

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.

In November 2019, the EPA proposed to revise the 2015 effluent limitation guidelines as they relate to existing facilities. The proposed new standards apply to flue gas desulfurization wastewater and bottom ash transport water and are meant to achieve greater pollution reductions than the 2015 standards by taking into account new and more affordable pollution control technologies. The final rule for steam electric power generation point sources 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. On May 9, 2024, the EPA finalized a supplemental rulemaking for coal-fired plants to strengthen certain wastewater discharge limits.

Climate Change. Legislative and regulatory responses to climate change and the effects of climate change could impact the future operations and costs of the Electric System or individual projects. In addition to the matters discussed above, the City may be impacted by future treaties and federal and state laws, rules and regulations that limit carbon dioxide and other GHG emissions from electric generating facilities. Absent legislative action by the U.S. Congress, the EPA has authority to regulate carbon dioxide and other GHG emissions under the Clean Air Act, and any future administrations could promulgate new rules or rules that repeal, revise and/or replace rules that are currently in effect. Furthermore, changes in temperatures, precipitation and the frequency and severity of extreme weather events (such as tornadoes and flooding) and other impacts of climate change could affect peak demands, the operations of the City's Electric System and the costs of maintaining Electric System facilities and power transmission lines. The impacts of these weather events on current and future operations cannot be predicted at this time.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects of 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 Electric System.

Resource Adequacy

Resource adequacy requirements apply to the Electric System and are intended to ensure that the Electric System has contracted for sufficient amounts of power resource capacity to meet its customers' needs. To the extent that the Electric System fails to procure sufficient capacity resources to meet its loads, it is subject to payment of CAISO procurement costs of replacement capacity. To the extent that a shortage cannot be attributed to procurement shortfalls, then the costs will be spread as part of market uplift charges. These risks apply in the same manner to all load-serving entities. Because of the increased integration of renewable energy sources, the CAISO is contemplating what could be significant changes to the resource adequacy framework, with the potential for impacts on market participant costs. It is still too early to assess the potential impacts on the Electric System. The CPUC has ongoing dockets that could also result in changes to resource adequacy and CAISO market requirements. However, the details of such changes remain to be established.

In 2006, the CAISO filed with FERC its Market Redesign and Technology Upgrade ("MRTU") tariff amendment to implement a comprehensive overhaul of the electricity markets administered by the CAISO. The programs under the MRTU initiative were designed to implement market improvements to assure grid reliability and more efficient and cost-effective use of resources and to create technology upgrades that would strengthen the entire CAISO system. The California energy market under the MRTU includes the following features, among others, which were not part of CAISO's previous real-time only market tariff:

- An integrated forward market for energy, ancillary services and congestion management that operates on a day-ahead basis;

- Congestion management which represents all network transmission constraints;

- Congestion Revenue Rights to allow market participants to manage their costs of transmission congestion;

- Local energy prices by price nodes (approximately 3,000 nodes in total), also known as locational marginal pricing; and

- New market rules and penalties to prevent gaming and illegal manipulation of the market as well as modifications to certain existing market rules.

The MRTU became operational on April 1, 2009 and the initial MRTU tariff filed with FERC went into effect at that time. Power is scheduled on a nodal basis, rather than the previous zonal system. Furthermore, the MRTU incorporates the CPUC's resource adequacy requirements to ensure that there are adequate power resources in critical areas. The MRTU requires that scheduling coordinators for all load-serving entities ("LSEs"), which include the City, meet standards concerning forward capacity and power procurement to meet their load requirements.

In September 2005, the Governor signed into law Assembly Bill 380 ("AB 380"), which requires publicly owned utilities to procure adequate capacity and power resources to meet their peak demands and reserves. In October 2005, the CPUC issued a decision requiring that LSEs under its jurisdiction acquire capacity that is sufficient to serve their forecast retail customer load plus a 15-17% reserve margin. The MRTU tariff incorporates the CPUC's resource adequacy requirements. The MRTU tariff imposes a 15% reserve margin on LSEs that are not CPUC jurisdictional entities, such as the City. Increasing the minimum 15% reserve margin is being considered as part of potential changes to the CAISO's resource adequacy framework.

The Electric System has historically satisfied its reserve margin requirement through its power supply resources, and the City believes that it will continue to have sufficient power resources to satisfy system capacity requirements as required by the MRTU and AB 380.

State Legislation Affecting the Power Supply

A number of bills affecting the electric utility industry have been introduced or enacted by the State Legislature in recent years. In general, these bills reflect California climate policy developments by regulating greenhouse gas ("GHG") emissions and providing for greater investment in energy efficiency and environmentally friendly generation and storage alternatives, principally through more stringent RPS requirements and more aggressive emissions reduction programs to combat the effects of climate change. Legislation enacted in recent years has also focused on addressing issues relating to wildfire risks. Set forth below is a brief summary of some of these bills and regulatory proceedings.

Senate Bill 350 – Clean Energy and Pollution Reduction Act of 2015. Senate Bill ("SB") 350, enacted in 2015, consists of a multitude of requirements to meet the Clean Energy and Pollution Reduction Act of 2015. The primary components that affect Riverside are: (i) the increase in the mandate of the State's Renewable Portfolio Standard ("RPS") to 50% by December 31, 2030; (ii) the doubling of energy efficiency savings by January 1, 2030; and (iii) providing for the transformation of the CAISO into a regional organization. In addition, there is a specific integrated resource planning mandate embedded in the bill that applies to the 16 publicly-owned utilities ("POUs") that have an annual electrical demand exceeding 700 GWh over a 3-year average, which includes the Electric System.

The bill also requires that an updated RPS Procurement Policy must be approved and adopted before January 1, 2019 and be incorporated into the Electric System's Integrated Resource Plan (IRP). An Updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. In parallel, on or before January 1, 2019, the governing board of the Electric System must adopt an IRP and a process for updating the plan at least once every 5 years. The IRP must address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhanced distribution systems and demand-side management, etc. The IRP must be submitted to the CEC for review, of which the CEC will check if the statutory requirements have been met and will adopt guidelines to govern the submission of the IRP information. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines.

On September 30, 2017, the Governor signed SB 338, which requires that the governing board of local POUs consider as part of the IRP process the role of existing renewable generation, grid operational efficiencies, energy storage, energy efficiency, and distributed energy resources in meeting the energy and reliability needs of each utility during the hours of peak demand. On August 1, 2018, the CEC adopted a Second Edition of the POU IRP Submission and Review Guidelines to include the requirements of SB 338. On October 3, 2018, the CEC adopted an amendment to the second edition guidelines to include the CARB's GHG emission reduction planning targets for IRPs.

On November 26, 2018 and December 11, 2018, the Board of Public Utilities and City Council, respectively, adopted the Electric System's 2018 Integrated Resource Plan. The IRP and additional submittal requirements were submitted to the CEC on December 18, 2018. In April 2019, the CEC issued their Staff Paper Review of the Electric System's IRP, as well as the CEC Executive Director's Determination Letter finding the Electric System to be consistent with the requirements of SB 350. The adoption of this determination occurred at the CEC Business meeting on August 14, 2019.

For the 5-year IRP update cycle mandated by SB 350, on August 5, 2022, the CEC published a Draft Revised Third Edition of the POU IRP Submission and Review Guidelines to reflect the SB 100 RPS procurement target of 60 percent of retail sales by 2030 and extend the IRP forecast horizon from 2030 to 2045. The Electric System completed an updated IRP as per the guidelines, and on April 8, 2024 and June 11, 2024, the Board of Public Utilities and City Council, respectively, adopted the Electric System's 2023 Integrated Resource Plan. The IRP and additional submittal requirements were submitted to the CEC on June 12, 2024. The Electric System is awaiting the CEC's review of its 2023 IRP.

The CEC continues to host various workshops on different components of the SB 350 requirement and the Electric System has been monitoring its outcome.

Senate Bill 100 – 100 Percent Clean Energy Act of 2018. On September 10, 2018, the Governor signed into law the 100 Percent Clean Energy Act of 2018 (SB 100). This bill further increases the RPS goals of SBX1-2 and SB 350, while maintaining the 33% RPS target by December 31, 2020, but modifying the future RPS percentages to be 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. The current end goal of SB 100 is to have 100% of the state's retail electricity supply generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045.

The CEC is required to establish appropriate multi-year compliance periods for all subsequent years after 2030 that will require POUs to procure not less than 60% of retail sales from renewable resources. In September 2019, the CEC began conducting pre-rulemaking workshops to discuss potential amendments to the RPS Enforcement Procedures for POUs that would incorporate the SB 100 mandates. In addition, POUs will need to include the increased requirements in their future IRP. On December 1, 2020, the CEC released the third 15-day language for the RPS Enforcement Procedures for POUs and adopted it at the December 22, 2020 CEC Business Meeting. It was approved by the Office of Administrative Law (OAL) and made effective July 12, 2021. The updated procedures clarify the interim targets for each year and that compliance periods beginning on and after January 1, 2031, shall be three years in length starting on January 1 and ending on December 31. For each compliance period beginning on or after January 1, 2031, a POU shall demonstrate it has procured electricity products within the compliance period sufficient to meet or exceed an average of 60 percent of the POU's retail sales over the three calendar years of the compliance period.

On December 4, 2020, the CEC issued a draft SB 100 Joint Agency Report, presented by the CEC with the CARB and CPUC. The joint agency report is intended to inform policy and planning, which is required to be presented to the legislature every four years starting on January 1, 2021. The final report was published by the CEC and joint agencies on March 15, 2021. On August 22, 2023, the CEC, the CARB, and CPUC held a joint workshop to discuss findings and recommendations from the 2021 SB 100 Joint Agency Report and the plan to address these findings and recommendations as the 2025 SB 100 Joint Agency Report is being developed. In 2024, the CEC began hosting workshops to discuss demand scenarios, as well as inputs and assumptions, for use in the 2025 SB 100 Joint Agency Report. The final report is expected to be adopted in late 2024. Riverside will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

Senate Bill 1020 – Clean Energy, Jobs, and Affordability Act of 2022. SB 1020, the Clean Energy, Jobs, and Affordability Act of 2022, was signed into law by the State Governor in September 2022 and became effective on January 1, 2023. SB 1020 revises SB 100's policy on eligible renewable energy resources and zero-carbon resources, and establishes that it is the policy of the State that eligible renewable energy resources and zero-carbon resources 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; and (iv) 100% of electricity procured to serve all state agencies by December 31, 2035.

Assembly Bill 1279 – California Climate Crisis Act. In September 2022, the State Governor signed into law Assembly Bill ("AB") 1279, which became effective on January 1, 2023 and established additional GHG emission reduction goals. AB 1279 declares the policy of the State both to achieve net-zero GHG emissions as soon as possible, but no later than 2045, and to achieve and maintain net negative GHG emissions thereafter, and to ensure that by 2045, Statewide anthropogenic GHG emissions are reduced to at least 85% below the 1990 levels. Under AB 1279, "net zero GHG emissions" means emissions of GHGs to the atmosphere are balanced by removals of GHG emissions over a period of time. AB 1279 directed the California Air Resources Board ("CARB") to ensure that its scoping plan identifies and recommends measures to achieve these policy goals. The State Legislative Analyst's Office is required to conduct an independent assessment of progress towards the bill's objectives every two years and to make its findings available to the public.

Assembly Bill 32 – Global Warming Solutions Act of 2006. AB 32, enacted in 2006, requires that utilities in California reduce their GHG emissions to 1990 levels by the year 2020. On September 8, 2016, the Governor of California expanded on this bill by approving SB 32, which requires the state board to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030.

AB 32 tasked the California Air Resources Board (CARB) to develop regulations for GHG, which became effective January 1, 2012. Emission compliance obligations under the cap-and-trade regulation began on January 1, 2013. The Cap-and-Trade Program (Program) was implemented in phases with the first phase starting from January 1, 2013 to December 31, 2014. This phase placed an emission cap on electricity generators, importers and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases per year. In 2015, the program expanded to cover emissions from transportation fuels, natural gas, propane, and other fossil fuels. Since the enactment of AB 32, the

Electric System has actively participated with major investor-owned utilities and POUs to affect the final rules and regulations with respect to AB 32 implementation.

The Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. CARB will provide a free allocation of GHG allowances to each electric utility to mitigate retail rate impacts. If a utility requires additional allowances, then they must be purchased through the auction or on the secondary market to offset its associated GHG emissions. Each allowance can be used for compliance purposes in the current year or carried over for use for future year compliance. The Electric System's free allocation of GHG allowances is expected to be sufficient to meet the Electric System's direct GHG compliance obligations.

Any allowance not used for current year compliance or carried over for future use in compliance must be sold into the quarterly allowance auctions administered by CARB. Proceeds from the auctions must be used for the intended purposes specified in AB 32, which include but are not limited to procurement of renewable resources, energy efficiency and conservation programs and measures that provide clear GHG reduction benefits. The Electric System is segregating the proceeds from the sales of allowances in the auctions as a restricted asset.

Similar to the Cap-and-Trade Program, the Low Carbon Fuel Standard (LCFS) Program is a key component of the market mechanisms authorized by AB 32 to achieve the State's GHG emissions reduction goals. LCFS seeks to reduce the carbon intensity (CI) of fuels used for transportation by establishing an annual CI target. Fuels that have a CI greater than the target have a compliance obligation and are required to turn in LCFS credits, while fuels with a CI lower than the target may generate credits.

In 2009, the LCFS rulemaking began and consisted of two rulemaking packages (Part 1 and Part 2) that were approved by the CARB on January 12, 2010 and April 15, 2010, respecitively, with implementation effective January 1, 2011. The program then underwent litigation in the State of California and the regulation was re-adopted with modifications on November 16, 2015, effective January 1, 2016. Under the LCFS program, electricity is considered a fuel subject to the regulation when it is used as a transportation fuel in electric vehicles. However, because the CI of electricity is substantially lower than the annual CI targets under the program, electricity is categorized as a fuel that generates LCFS credits and participation in the program is voluntary.

In March 2018, the City opted into the LCFS program and began generating LCFS credits for the first quarter of 2018. These credits are associated with two sources – unmetered electricity used to charge residents' electric vehicles at their homes (residential base credits) and from electric forklifts charging at private businesses (forklift credits). CARB calculates the credits that the Electric System will receive and the Electric System submits quarterly reports to receive the credits. The Electric System has established a restricted regulatory requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the LCFS proceeds. The available funds are to be utilized for qualifying programs that support the Electric System's customers who are existing and future electric vehicle owners.

Simultaneously in 2018, the LCFS regulation was amended and adopted on January 4, 2019. The amendments required electric utilities that have opted into the LCFS Program to participate in and manage a statewide point-of-sale rebate program for new electric vehicles. This program is called the California Clean Fuel Reward Program (CFR) and the City joined the program in May 2020. To fund the program, electric utilities are required to contribute proceeds received from the sales of residential base credits beginning with the credits the Electric System received in the fourth quarter of 2019 (generated from electricity used for transportation in the second quarter of 2019). Residential base credits the Electric System received prior to that time are not subject to the contribution requirements. Additionally, a "startup" contribution from proceeds was required to be submitted by January 31, 2021. After the initial deposit of funds in November 2020, deposits to the CFR program are required by March 31 annually.

The CARB is currently in the midst of a new rulemaking process in which proposed amendments are anticipated to be considered in November 2024. The proposed amendments include changes to the residential base credits program including increasing the amount of holdback credit proceeds that must be used to support transportation electrification in disadvantaged communities to 75% and the possibility of up to 45% of base credits going to original equipment manufacturers (OEMs). If credits are directed to OEMs, electric utilities will no longer be required to contribute funds to the CFR program. Additional proposed amendments include the addition of an automatic acceleration mechanism for annual carbon intensity benchmarks and additional verification requirements for annual compliance reports. The Electric System will continue to monitor the outcome and impacts of this rulemaking on its transportation electrification programs.

Assembly Bill 398 – GHG Cap-and-Trade Program Extension. AB 398 was signed on July 25, 2017 and approved extending the GHG cap-and-trade program to December 31, 2030, which was originally implemented under AB 32. This bill was also a companion bill to AB 617 as part of a legislative package that will be discussed further below. In addition, AB 398 required the CARB to update their scoping plan no later than January 1, 2018. AB 398 also requires all adopted GHG rules and regulations to be consistent with this plan. On July 27, 2017, the CARB approved the 2016 Cap-and-Trade Amendments, which includes the Electric System's 2021-2030 allowance allocations it will receive each year. The Electric System's allowance allocations should be sufficient to cover all of its 2021-2030 direct compliance obligations.

Initially, it was unclear under AB 398 whether the Electric System would be required to consign 100% of its allowances to the market and then purchase allowances to fulfill its compliance obligations. Since the start of the Cap-and-Trade program in 2012, POUs have been able to directly assign allowances for compliance. However, in 2017, the CARB announced they were reconsidering this provision. In early 2018, after much discussion and collaboration with the CARB in which the POUs demonstrated that they continue to include the price of GHG emissions in the cost of energy, it was agreed that the POUs would not be forced to consign their allocated direct-compliance allowances to auction. Other unknown components of the law include the banking provisions and the specific GHG revenue spending requirement for revenues generated from the sale of excess allowances.

In June 2021, the CARB began focus area discussion workshops as part of the next iteration of the Scoping Plan Update on four areas: 1) electricity sector, 2) transportation sector, 3) equity and environmental justice, and 4) natural and working lands. On June 8, 2021, the CARB hosted a workshop series to commence development of the 2022 Scoping Plan Update to Achieve Carbon Neutrality by 2045. Starting in July 2021 and onward, a series of technical workshops were hosted to cover various topics and sectors within the Scoping Plan. On December 15, 2022, the CARB Board unanimously adopted the 2022 Scoping Plan Update. The Scoping Plan focuses on laying out the path to achieving carbon neutrality and reducing anthropogenic GHG emissions by 85 percent below 1990 levels no later than 2045. The 2022 Scoping Plan includes decarbonization through the electrification of transportation and buildings which will increase the transportation and generation needs of the Electric System. The Scoping Plan also states that storage and demand-side management will be essential to maintaining reliability as more renewables are incorporated into the electric grid.

On July 27, 2023, the CARB held a workshop on the potential amendments to the cap-and-trade regulation. The CARB is again proposing the requirement for consignment of POU allocations, which would add significant cost uncertainty into energy pricing and require the Electric System to purchase allowances from auction using alternative ratepayer funds. Potential impacts also include a decrease of annual allowance allocations and impacts to the Mandatory Reporting Requirement (MRR). The CARB has shown a particular interest in ensuring that allowance value targets low-income and priority communities. The CARB has continued to hold public workshops throughout 2023 and 2024 to solicit feedback on potential amendments. It is anticipated that the formal rulemaking will begin in late 2024 with the goal of the new regulations becoming effective early 2025. The Electric System will continue to monitor the outcome and impacts of the upcoming regulations on its service territory and ratepayers.

Assembly Bill 617 – Air Quality Monitoring. AB 617 was signed on July 26, 2017 and was part of a legislative bill package with AB 398, which authorized the extension of the cap-and-trade program in the State. AB 617 addresses the disproportionate impacts of air pollution in areas impacted by a combination of economic, health, and environmental burdens. These burdens include combinations of poverty, high unemployment, health conditions such as asthma and heart disease, air and water pollution, and hazardous wastes. Both the CARB and local air districts are required to take specific actions to reduce air pollution and toxic air contaminants from commercial and industrial sources, including from electricity-generating facilities. The bill required the CARB, by October 1, 2018, to prepare a statewide monitoring plan regarding technologies and reasons for monitoring air quality and, based on that plan, identify the highest priority locations for the deployment of community level air monitoring systems. Local air districts are required to deploy the air monitoring systems in the specified communities by July 1, 2019. Additional locations for the deployment of the systems will be identified annually by the CARB beginning January 1, 2020. The CARB is also required to provide grants to community-based organizations for technical assistance and to support community participation in the programs. In turn, this effort would require the local air district of the selected community to adopt a community emissions reduction program.

Additionally, AB 617 requires CARB to develop uniform reporting standards for air pollutants and toxic air contaminants for specific uses, including electricity-generating facilities. Air districts are to adopt an expedited schedule for implementing best available retrofit control technologies for the uses, while CARB will identify these technologies.

This bill affects the City and the Electric System by imposing additional reporting requirements, particularly on power plants, and potentially adding or improving air monitoring systems in selected communities located within the City of Riverside. For Riverside, the local air district is the Southern California Air Quality Management District ("SCAQMD"). The CARB and SCAQMD have held and continue to hold community meetings to implement the required elements of AB 617. Preliminary discussions and proposals have already been conveyed by community members from the City as well as from the University of California, Riverside proposing areas for community air monitoring and planning. The City and Electric System are monitoring the progress of the community meetings and the two proposed areas for any impacts.

Senate Bill 1368 – Emission Performance Standard. The state legislature passed SB 1368 in 2006, which mandates that electric utilities are prohibited from making long-term financial commitments (commitments greater than five years in duration) for generating resources with capacity factors greater than 60% that exceed a GHG emission factor of 1,100 pounds/MWh. SB 1368 essentially prohibits any long-term investments in generating resources based on coal. Thus, SB 1368 initially disproportionally impacted Southern California POUs, as these utilities had heavily invested in coal technology. However, additional legislation such as SBX1-2, SB 350, SB 100, and SB 32 have now led to a gradual decrease in the generation of existing coal resources to serve load.

Riverside has ownership entitlement rights to 136 MW of IPP. IPP has a GHG emission factor of approximately 2,000 pounds/MWh. Therefore, under SB 1368, Riverside is precluded from renewing its IPP Power Purchase Contract at the end of its term in June 2027.

Going forward, SB 1368-related issues are expected to have minimal impact to the CAISO markets as the percentage of load served by coal resources is small. However, to the extent that significant numbers of coal plants throughout the western United States start to retire in the next 5 to 15 years, it is possible that there could be a tightening of supply throughout the western United States electricity market. In turn, this could lead to higher regional costs and potentially reduced system reliability.

Senate Bill 1037 – Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037") was signed into law by the State Governor in September 2005. The law requires publicly owned electric utilities, when procuring energy for long-term needs, to first acquire all available energy efficiency, demand reduction and renewable resources that are cost effective, reliable and feasible. SB 1037 also requires Riverside to report annually to its customers and to the State its investment in energy efficiency and demand reduction programs. Riverside is complying with these reporting requirements.

Assembly Bill 2514 – Energy Storage. AB 2514 "Energy Storage Systems" was signed into law on September 29, 2010. In 2012, AB 2227 amended the reporting timeline of the energy storage targets referenced in AB 2514. The law directs the governing boards of POUs to consider setting targets for energy storage procurement, but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. The law's main directives for POUs and their respective deadlines are as follows: (a) to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems, and (b) to adopt an energy storage system procurement target by October 1, 2014, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2020. POUs were required to submit compliance reports to the CEC of their first adopted target by January 1, 2017.

Energy storage ("ES") has been advocated as an effective means for addressing the growing operational problems of integrating intermittent renewable resources, as well as contributing to other applications on and off the grid. In general, ES is a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydroelectric generation, compressed air systems, batteries and thermal ES systems.

On February 17, 2012, as per the statute, the City of Riverside's Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if the City should adopt a 2016 energy storage procurement target. The City finished its investigation of energy storage pricing and benefits in September 2014 and adopted a zero-megawatt target based on the conclusion that the viable applications of energy storage technologies and solutions at the time were not cost effective and outweighed the benefits that it might provide to our electrical system. The City had to reevaluate its assessment by October 1, 2017 and report to the CEC any modifications to its initial target resulting from this reevaluation.

On March 3, 2015, City Council approved the Ice Bear Pilot program for 5 MW. The program is intended to reduce load during peak hours by shifting load to off-peak hours, improve energy efficiency, and demonstrate the City's proactive support of the State's energy storage goals. Additionally, on July 28, 2015, the City Council approved a 20-year power purchase agreement for the City to procure renewable energy from the Antelope DSR Solar Photovoltaic Project that includes a built-in energy storage option for the buyers to exercise during the first fifteen years of operation.

On December 12, 2016, Riverside submitted its first compliance report to the CEC describing Riverside's proactive efforts in investigating viable energy storage options in the market and conducting energy storage pilot projects within the City to fulfill its first adopted target.

On September 11, 2017 and September 26, 2017, after reevaluating its assessment of the first adopted energy storage procurement target of zero megawatts, the Riverside Board and City Council, respectively, approved and adopted the second energy storage procurement target of six megawatts for submittal to the CEC.

Senate Bill 380 – Moratorium on Natural Gas Storage – Aliso Canyon. On October 23, 2015, a significant gas leak was discovered at the Aliso Canyon natural gas storage facility, which makes up 63%

of total storage capacity of Southern California Gas Company and serves 17 gas fired power generation units. On May 10, 2016, the State Governor signed SB 380, placing a moratorium on Aliso Canyon's natural gas storage usage until rigorous tests were performed and completed by the Division of Oil, Gas, and Geothermal Resources ("DOGGR") as to which wells could continue to be in operation. This moratorium caused great concern regarding the reliability of natural gas supplies in the upcoming summer and winter months. An action plan study area was initiated to review the summer and winter assessment that was conducted as a joint effort between the CPUC, CEC, CAISO and Los Angeles Department of Water and Power. Although the area of study neither includes nor immediately impacts Riverside, it is highly plausible that the Electric System could still experience curtailed gas deliveries under certain adverse low-flow gas scenarios.

Beginning June 1, 2016, Southern California Gas Company (SoCalGas) implemented new Operational Flow Order (OFO) tariffs due to limitations surrounding Aliso Canyon storage injections and withdrawals. These tariff changes were put in place to reduce the probability of natural gas curtailments, which would disproportionally impact Riverside due to the requirements to operate internal natural gas generation to maintain system reliability during the summer. Also, gas curtailments during high peak days could lead to severe service curtailments throughout Riverside. Therefore, the Electric System immediately increased internal communication across divisions, created internal gas curtailment procedures to address this specific issue, and created revised dispatch procedures when load forecasts exceed 400 MW. These tighter OFO tariff restrictions were scheduled to conclude upon the return of Aliso Canyon to at least 450 million cubic feet per day (MMcfd) of injection capacity and 1,395 MMcfd of withdrawal capacity. Aliso Canyon had not been able to meet its injection and withdrawal targets, therefore, these tighter OFO tariff restrictions continued to remain in effect. In addition, the Electric System continues to communicate daily with the CAISO and SoCalGas on any changes that could impact our service territory.

On February 9, 2017, pursuant to SB 380, the CPUC opened a three-phase investigation to determine the feasibility of minimizing or eliminating the use of Aliso Canyon. On July 19, 2017, DOGGR issued a press release on their determination, in concurrence with the CPUC, that Aliso Canyon was safe to resume injections up to 28% of the facility's maximum capacity. On that same day, the CEC issued a different press release with a recommendation urging closure of Aliso Canyon in the long-term. On July 31, 2017, SoCalGas resumed injections. Effective July 23, 2019, the CPUC approved the Aliso Canyon Withdrawal Protocol, a protocol describing the process to follow before making a withdrawal from the natural gas storage facility. The protocol was developed with input from the CEC, the CAISO, and LADWP, and enables SoCalGas to withdraw from the Aliso Canyon natural gas storage facility when specific conditions are met related to Low Operational Flow Order (OFO) calculations, Southern California natural gas inventory levels, and/or emergency conditions.

Senate Bill 380 added Section 715 to the Public Utilities Code (PUC), which requires the CPUC to determine the range of Aliso Canyon inventory necessary to ensure safety, reliability, and just and reasonable rates. In the Section 715 Report, the Energy Division of the CPUC recommended that the maximum allowable Aliso Canyon inventory increase from 24.6 to 34 billion cubic feet (Bcf) for summer 2018 and going forward, due to continuing pipeline outages on the SoCalGas system. As of October 7, 2020, the final results of the 114 injection well tests are as follows: 66 wells have completed all required tests and have received final DOGGR (now the California Geologic Energy Management Division (CalGEM)) approval; 27 wells have been taken out of operation; and 21 wells have been plugged and abandoned. The CalGEM reduced the Aliso Canyon safe inventory limit from 86Bcf to 68.6Bcf.

On November 4, 2021, the CPUC voted to allow SoCalGas to increase the amount of natural gas inventory at the Aliso Canyon Natural Gas Storage Facility from 34Bcf to 41.16Bcf, to ensure SoCalGas meets minimum reliability needs.

On September 23, 2022, the CPUC issued a Ruling that finds based on the investigation analysis, that the Aliso Canyon Natural Gas Storage Facility is needed to maintain the reliability of the natural-gas system and to help stabilize gas and electric rates until other resources are available to serve the Los Angeles Basin. In the same Ruling, the CPUC sought comments on a Staff Proposal presenting a framework to eliminate the need for Aliso Canyon by increasing non-gas-fired electricity generation and storage, building electrification, and energy efficiency. The proposal quantifies the current need for Aliso Canyon and estimates an annual increase of 1,084 MW of non-gas-fired electric generation capacity to reliably serve all energy demand without the use of Aliso Canyon by 2027. Because natural gas and electricity systems and demands are constantly evolving, this proposal suggests a biennial assessment where staff from the CPUC and CEC update supply and demand information and consider whether gas demand reductions are on track with proposed targets. If not, staff will consider whether those targets should be adjusted. If gas demand is declining on pace to meet or exceed targets, staff would recommend whether the maximum storage inventory at Aliso should be reduced. This process would continue every other year until Aliso Canyon is phased out.

In winter 2022-23, California and the Western U.S. experienced historically high natural gas prices due to widespread, below-normal temperatures; high natural gas consumption; pipeline constraints; reduced natural gas flows; and low storage inventories. On August 31, 2023, the CPUC approved an increase to the maximum storage level allowed at Aliso Canyon from 41.16Bcf up to the safety limit set by CalGEM of 68.6Bcf. The decision allows more natural gas to be injected and stored at Aliso Canyon to help secure energy reliability and protect against high natural gas and electric prices. The decision will not impact progress in proceeding towards phasing out the need for Aliso Canyon.

Assembly Bill 802 – Building Energy Use Benchmarking and Public Disclosure Program. On October 8, 2015, AB 802 was signed into law creating a new statewide building energy use benchmarking and public disclosure program for the State of California. The bill requires California utilities to maintain records of energy usage data for all buildings (i.e., commercial and multifamily buildings over 50,000 square feet gross floor area) for at least the most recent 12 months. Beginning January 1, 2017, utilities are required to deliver or provide aggregated energy usage data for a covered building, as defined, to the owner, owner's agent or operator upon written request. The Electric System provides consumption data for buildings meeting the legislative requirement upon owners' written request. The CEC adopted regulations on October 11, 2017 and approved the regulation action to be effective on March 1, 2018. Building owners are required to report this information annually beginning on June 1, 2018.

Assembly Bill 1110 and Senate Bill 1158 – Legislation Relating to Greenhouse Gas Emissions Reporting for Power Resource Disclosure. On September 26, 2016, AB 1110 was signed into law requiring GHG emissions intensity data and unbundled renewable energy credits (RECs) to be included as part of the retail suppliers' power source disclosure (PSD) report and power content label (PCL) to their customers. GHG emissions intensity factors will need to be provided for all retail electricity products. The inclusion of this new information requirement on the PCL will begin in 2021 for calendar year 2020 data. In addition to still being required to post the PCL on the city website, the bill also reinstated the requirement that the PCL disclosures must be mailed to the customers starting in 2017 for calendar year 2016 data unless customers have opted for electronic notifications. In accordance with this requirement, Riverside reinstated the inclusion of printed disclosures of the PCL with its September 2017 bills to the customers.

In 2017, the CEC began hosting workshops on the GHG emissions disclosure requirements and initiated the rulemaking process of updating their PSD regulations. A pre-rulemaking phase also began that included an implementation proposal on AB 1110. The legislation requires the CEC to adopt guidelines by January 1, 2018. In early 2018, the CEC provided an update to their 2017 pre-rulemaking activities and proposed changes to the regulations and reports, but additional workshops were needed. In March 2019, the last pre-rulemaking workshop was held by the CEC, with the intent to begin the formal rulemaking in May, but was delayed until September 2019. On December 11, 2019, the CEC adopted the updated PSD regulations, which changed the timing of the inclusion of the GHG emissions intensity data to be included in the PCL starting in 2021 for calendar year 2020 data. The adoption of the updated PSD regulations and how the additional GHG emissions intensity information would be conveyed to customers in the PSD report and PCL was approved on May 4, 2020. The most notable changes to the report and label are the addition of the GHG emissions intensity and how certain energy resources would be conveyed to the customers to meet the AB 1110 requirement.

On September 16, 2022, Senate Bill (SB) 1158 was signed into law which requires, beginning January 1, 2028, every retail supplier to annually report to the CEC information concerning electricity supply used to serve load, including the retail supplier's hourly sources of electricity and the emissions of GHG associated with those sources of electricity. The bill also requires the CEC to share and publish the information annually on its website in an aggregated summary. The CEC is required to adopt rules to implement these reporting requirements on or before July 1, 2024. The CEC initiated the formal rulemaking period on May 17, 2024 by releasing an initial 45-day language package and hosted a rulemaking workshop on June 11, 2024 to solicit feedback on the proposed changes. It is anticipated that the CEC will be releasing an additional 45-day language package in Fall 2024. Riverside continues to monitor upcoming workshops and draft regulations for any impacts to the utility's reporting and portfolio of resources.

Senate Bill 859 – "Budget Trailer Bill" – Biomass Mandate. In the final two days of the 2015-2016 legislative session, a "budget trailer bill" on how to spend cap-and-trade funds was amended to include a biomass procurement mandate for local publicly-owned utilities serving more than 100,000 customers. These utilities would be required to procure their pro-rata share of the statewide obligation of 125 MW based on the ratio of the utility's peak demand to the total statewide peak demand from existing in-state bioenergy projects for at least a five-year term. On September 14, 2016, the Governor of California signed SB 859 into law.

On October 13, 2016, the CPUC adopted Resolution E-4805, which established that the POUs be allocated 29 MW of the 125 MW statewide mandate. The City determined that their obligated share would be 1.3 MW to meet the mandate. It is expected that the City's proportion of these facilities will be counted towards the Electric System's Renewable Portfolio Standard (RPS) goals.

In 2017, the affected POUs consisting of the cities of Anaheim, Los Angeles, and Riverside, Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District decided it would be beneficial to procure a contract together for economies of scale. This was accomplished by utilizing SCPPA to issue a Request for Proposal on behalf of all the affected POUs, since four of the seven POUs affected are existing SCPPA members.

In January 2018, the Riverside Board and City Council approved the City's five-year Power Sales Agreement with SCPPA for 0.8 MW from the ARP-Loyalton biomass project. On April 20, 2018, the facility declared commercial operation.

On September 21, 2018, the Governor signed into law SB 901, which primarily focuses on strengthening California's ability to prevent and recover from catastrophic wildfires such as via forest management activities, updating requirements for maintenance and operations of utility infrastructure, assessing GHG emissions impact, and protecting ratepayers. The bill also included a clause for certain biomass contracts that were procured or operating in 2018 and set to expire on or before December 31, 2023 to be offered a contract extension. The Electric System is required to "seek to amend the contract to include, or seek approval for a new contract that includes, an expiration date 5 years later than the expiration in the contract". Although there is no enforcement mechanism, the ARP-Loyalton biomass project meets the above criteria and feedstock requirement referenced in SB 901 and SB 859. The Electric System had been working with ARP-Loyalton to comply with SB 901, but production generation from the project site ceased in early January 2020. In late February 2020, ARP-Loyalton filed for Chapter 11 bankruptcy. Sale of the project was approved by the court to a new owner on April 30, 2020. The term of the Agreement ended on April 19, 2023, fulfilling the regulatory requirements, and on April 30, 2024, the courts approved the bankruptcy filing and associated settlement, which reimbursed the contractors for all the legal fees associated with the bankruptcy.

On February 24, 2020 and March 17, 2020, Riverside's Board and City Council, respectively, adopted a five-year Purchase Agreement with Roseburg Forest Products Co. for 0.5 MW in capacity to fulfill the remaining MW share of the mandate. On February 16, 2021, Roseburg declared commercial operation.

Senate Bill 1109 – Extension of Biomass Mandate. Senate Bill 1109 ("SB 1109"), signed into law by the State Governor on September 16, 2022 (and effective on January 1, 2023), modifies SB 859, requiring publicly owned utilities that serve more than 100,000 customers to procure, by December 1, 2023, through financial commitments of 5 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 if the utility, 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 included: (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 utility. SB 1109 will not impose additional requirements on Riverside because the City entered into the five-year financial commitments as previously required pursuant to SB 859. SB 1109 also modified SB 901's contract extension requirement, instead requiring utilities 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 Riverside under SB 1109.

Senate Bill 1028, Senate Bill 901, and Assembly Bill 1054 – Legislation Relating to Wildfires. SB 1028, which was signed into law by the State Governor in September 2016, requires municipal electric utilities to construct, maintain and operate their electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 also requires the governing board of each municipal electric utility to make an initial determination as to whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on historical fires and local conditions and if so, to present for board approval wildfire mitigation measures that the utility intends to undertake to minimize the risk. While governing boards must make this determination independently based on all relevant information, the CPUC's Fire Threat Map is an important factor in this process. The Fire Threat Map was adopted by the CPUC on January 19, 2018. According to the Fire Threat Map, parts of the Electric System are in an elevated fire threat zone. The Electric System owns transmission assets, including, but not limited to, wires, poles and other needed equipment to safely maintain and deliver power generated from generation assets located outside City limits.

SB 901, which was signed into law by the State Governor in 2018, addresses the response to, mitigation of and prevention of wildfires. SB 901 requires municipal electric utilities to prepare before January 1, 2020 and annually thereafter a wildfire mitigation plan (a "WMP"), which is to be submitted to a newly created Wildfire Safety Advisory Board (the "WSAB"). SB 901 further requires utilities to present their WMPs in an appropriately noticed public meeting, to accept comments on the plan from the public, other local and state agencies and interested parties and to verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. SB 901 also requires the utilities to contract with a qualified independent evaluator to review and assess the comprehensiveness of their WMPs. The report of the independent evaluator is to be made available on the Internet and to be presented at a public meeting of the utilities' governing boards.

Under AB 1054, which was signed into law in July 2019, the WSAB is required to provide comments and an advisory opinion to each publicly owned utility regarding the content and sufficiency of its plan and to make recommendations on the mitigation of wildfire risks. AB 1054 requires each publicly owned utility to comprehensively revise its WMP at least once every three years.

The City fully complied with AB 1054 and the City Council formally adopted the Wildfire Mitigation Plan on December 17, 2019. Following City Council adoption, this approved plan was also submitted to the WSAB on May 6, 2020, as required.

On December 9, 2020, the WSAB completed their review of all publicly owned utilities' initial WMPs and issued an advisory opinion applicable to all POUs. It identified several themes that all POUs were requested to address and were not required to incorporate the recommendations as part of the next annual WMP update. Instead, POUs were asked to respond to a matrix of questions to be submitted at the same time as the next update of the WMP. The matrix is not required to be presented to the public utilities' governing boards.

On June 14, 2021, the Electric System presented the updated 2021 WMP to its Board and received a recommendation that the City Council approve the 2021 Riverside Public Utilities WMP annual update for submittal to the WSAB by July 1, 2021. During the Board meeting, staff identified updates to the WMP that would allow the Electric System to better respond to the WSAB's advisory opinion that had not been incorporated into the WMP. Instead of bringing it before the City Council for approval as is, staff opted to remove the item from consideration in order to provide an updated 2021 Riverside Public Utilities WMP to the Riverside Board for approval again. The update to the 2021 Riverside Public Utilities WMP was approved on September 27, 2021 and October 12, 2021 by the Riverside Board and City Council, respectively.

On June 27, 2022, the Riverside Board approved the 2022 WMP which was then submitted to the WSAB on June 30, 2022. On October 17, 2022, the WSAB issued a guidance advisory opinion for the 2023 WMP for electric POUs and rural electric cooperatives. The advisory opinion included general guidance that applied to all POUs, specific guidance for each POU, and a template with instructions for preparing 2023 plans. All guidance was incorporated into Riverside's 2023 WMP. The 2023 WMP included the steps, programs, policies, and procedures implemented by the Electric System to reduce wildfire risks and minimize impacts to customers. As required by PUC Section 8387, a qualified independent evaluator was contracted to review and assess the 2023 WMP for comprehensiveness. The independent evaluator provided feedback on the plan, which the Electric System incorporated by including additional details to further clarify the Electric System's wildfire mitigation measures. Afterwards, the independent evaluator concluded that the Electric System's 2023 WMP was sufficient in meeting the requirements for comprehensiveness. On June 26, 2023 and July 18, 2023, the 2023 WMP and independent evaluator's findings were presented to the Riverside Board and City Council, respectively. The 2023 WMP was submitted to the WSAB on July 19, 2023.

The 2024 WMP was not required to be a comprehensive revision and therefore did not require an independent evaluator review. On June 10, 2024, the Riverside Board recommended approval of the 2024 WMP and on June 18, 2024, the City Council approved the 2024 WMP. The 2024 WMP was submitted to the WSAB on July 1, 2024.

For the wildfire fund, only voluntarily participating IOUs are eligible for claims arising from a covered wildfire. The POUs are not required nor able to join due to concerns and issues over complications of funding as a public entity. The bills do not address existing legal doctrine relating to utilities' liability for wildfires. However, any future legislation that addresses California's inverse condemnation and strict liability issues for utilities in the context of wildfires could be significant for the Electric System. Riverside is regularly engaged with the current WSAB meetings and updates, continues to partner with the Riverside

Fire Department, and is diligently monitoring the outcome and impacts of any upcoming legislation and regulations on its service territory and ratepayers.

Assembly Bill 205 – On-call Resources and Energy Storage. On June 30, 2022, AB 205 was signed into law to address several energy topics but more specifically, on-call emergency supply and load reduction for the State's electrical grid during extreme events to reduce the risk of blackouts. AB 205 requires the CEC to implement and administer the Distributed Electricity Backup Assets (DEBA) program to incentivize the construction of cleaner and more efficient distributed energy assets and the Demand Side Grid Support (DSGS) program to incentivize dispatchable customer load reduction and backup generation operation to be on-call for extreme events.

The initial DSGS program and guidelines launched in the Summer of 2022 and concluded October 2022. On July 26, 2023, the CEC adopted the second edition of the DSGS guidelines, which made the program effective immediately. On May 8, 2024, the CEC adopted the DSGS Guidelines, Third Edition. Through the program, participating customers receive a financial incentive for on-call load reduction during extreme events and the Electric System receives reimbursement for administrative costs to facilitate customer participation. The funding for the DSGS program was authorized by AB 205 and further expanded by AB 102 (signed on July 10, 2023), which stated the funding would be available for five years until June 30, 2027. On May 13, 2024 and June 11, 2024, the recommendation for the Electric System to allow customers to participate in a non-utility sponsored demand response program under the CEC DSGS State program was approved by the Riverside Board and City Council, respectively. The Electric System has begun authorization of enrolling customers in the CEC DSGS program, but no extreme events have been called upon by the CEC for this year.

On January 27, 2023, the CEC held a workshop to discuss the DSGS program and the DEBA program. Information from this meeting was used to inform the development of the DEBA program. Proposed DEBA guidelines were released on August 11, 2023, and were approved on October 18, 2023. The guidelines set aside 25% of program funding for projects in POU territories, which would be awarded through grant funding opportunity solicitations. In December 2023, the first DEBA grant funding opportunity was released for bulk grid asset enhancements focused on grid reliability. This program could potentially provide funding to the Electric System for additional bulk grid assets and/or distributed resources.

The Electric System will continue to monitor upcoming workshops and regulations for funding opportunities and any impacts on its service territory and ratepayers.

Assembly Bill 209 – Energy and Climate Change. On September 6, 2023, AB 209 was signed into law authorizing several energy programs to address climate change. One program is the Equitable Building Decarbonization Program. The program provides funding for a Statewide Direct Install Program, Tribal Direct Install Program, a Statewide Incentive Program, and provides support for existing programs. This program must serve under-resourced communities and can fund eligible measures such as heating and cooling, building envelope retrofits, water heating, cooking, and more. The program guidelines were adopted on October 18, 2024, and the program administrators were selected in August 2024. The program is expected to rollout to initial communities in late 2024 to early 2025.

AB 209 also established directives for allocating general funds to provide incentives for eligible residential customers, including publicly owned utility (POU) customers, for the Self-Generation Incentive Program (SGIP). SGIP provides incentives to support existing, new, and emerging distributed energy resources installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, fuel cells, advanced energy storage systems and more. On July 10, 2023, the Governor approved Senate Bill (SB) 123, clarifying that SGIP incentives are eligible for low-income residential customers who install behind-the-meter energy storage or photovoltaic systems. It also clarified that these incentives are available to POU customers.

Another program under AB 209 that the CEC must establish and administer is the Hydrogen Program to provide financial incentives to in-state hydrogen projects for the demonstration or scale-up of the production, processing, delivery, storage, or end use of clean hydrogen. The CEC held a workshop in December 2022 to provide an overview of the Clean Hydrogen Program and the proposed program scope, funding areas, and project requirements. On May 19, 2023, the CEC released a draft solicitation concept for large-scale centralized production to solicit public feedback. On May 23, 2023, the CEC released the "Cost Share for Federal Clean Energy Funding Opportunities" competitive solicitation, which is ongoing. In May 2024, Governor Newsom released the 2024-2025 Revised State Budget Proposal, which called for reducing the Clean Hydrogen Program funding to $40 million and delaying the majority of funding until fiscal year 2025-2026.

The Electric System will continue to monitor the development of these programs to determine opportunities and impacts on its service territory and ratepayers.

Senate Bill 48 – Building Energy Savings Act. On October 7, 2023, the Governor signed into law the Building Energy Savings Act (SB 48). This bill requires the CEC, in consultation with the CARB, CPUC, and Department of Housing and Community Development, on or before July 1, 2026, to develop a strategy for using the energy usage data collected from the benchmarking and disclosure program developed through AB 802. The CEC intends to develop a report that reflects the strategy and recommendations to track and manage the building energy usage and associated GHG emissions to achieve the State's equity, energy and emission goals, targets, and standards. The bill requires the CEC to submit the strategy and recommendations to the Legislature on or before August 1, 2026.

On July 31, 2024, the CEC held a workshop to kick off the development of the California Building Energy Performance Strategy Report to also include recommendations for further legislative action. The Electric System will continue to monitor the progress of the report for impacts on its service territory and ratepayers.

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"). This Appendix does not purport to cover all aspects of the Agency or the Intermountain Power Project ("IPP"). Except as set forth in "UPDATE INFORMATION" below, for important financial, operating and other information regarding the Agency, see (i) that certain Official Statement, dated October 25, 2024, as supplemented on November 15, 2024, filed by the Agency with the Municipal Securities Rulemaking Board (the "MSRB") through its Electronic Municipal Market Access system ("EMMA") (such Official Statement being the "Agency Official Statement") and (ii) the Agency's Annual Disclosure Report filed with the MSRB through EMMA on March 31, 2024 (the "Agency Annual Filing") which is incorporated by reference into and updated by the Agency Official Statement. The Agency Official Statement and the Agency Annual Filing are intended to be read in their entirety and in conjunction with each other. A copy of the Agency Official Statement and the Agency Annual Filing may be obtained from EMMA. Each term used but not otherwise defined in this Appendix has the meaning ascribed to such term in the Agency Official Statement.

The IPP Purchasers and the 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 "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Power Sales Contracts" in the Agency Official Statement.

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 "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Renewal Power Sales Contracts" in the Agency Official Statement.

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 Official Statement (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 entitled "Percentages of Capability of Generation Station to be Purchased," set forth in the section of the Agency Official Statement captioned "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers," 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.

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 "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" in the Agency Official Statement.

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 2024 SERIES A AND B BONDS – Agreement for Sale of Renewal Excess Power" in the Agency Official Statement, 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.

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.

The Agency is in the process of constructing, installing and updating gas units and related facilities to replace the IPP coal units as the source of generation of electricity at IPP. The construction of the Gas Repowering portion of the Generation Renewal Project is anticipated to be completed during the summer of 2025 sometime after the originally scheduled date of July 1, 2025. The Agency continues to assess the potential impact of the delay in the scheduled completion of that portion of the Generation Renewal Project. See "INTRODUCTORY STATEMENT – The Project and the Generation Renewal Project" in the Agency Official Statement for a description of (i) the operating history of IPP and (ii) the construction and installation of the Generation Renewal Project, including the Hydrogen Facilities.

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.

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UPDATE INFORMATION

The following information set forth in this Appendix B updates, modifies, supersedes and supplements portions of the Agency Annual Filing, as updated by APPENDIX A to the Agency Official Statement, as indicated below:

1. RISK FACTORS

The last paragraph under the section captioned "RISK FACTORS – Utah Legislative Actions" in the Agency Annual Filing is replaced in its entirety by the following:

On November 20, 2024, the Public Utilities, Energy and Transportation Committee of the Utah Legislature recommended passed out a bill that, if enacted by the Legislature and not vetoed by the governor, would prohibit, among other things, the Agency from disconnecting either of the IPP coal units from the IPP switchyard (the "Decommissioned Asset Disposition Amendments"). The requirement to keep the IPP coal units connected to the IPP switchyard would result in IPA not being able to connect synchronous condensers to the IPP switchyard in connection with IPP Renewed (the designation for all of the facilities being constructed and installed in connection with the IPP gas units, including the Generation Renewal Project and the STS Renewal Project). The synchronous condensers are necessary for maintaining the rating on the STS. IPA continues to work with the bill's sponsor in order to preserve the ability to complete construction and installation of IPP Renewed, including the synchronous condensers, while addressing the desires of the State of Utah to keep the IPP coal units available for operation by a third party in the event that permitting and other impediments can be addressed.

Even with the enactment of H.B. 3004, the Agency cannot predict the potential impacts of S.B. 161 on the operation of the Project or the construction and operation of the Generation Renewal Project, nor the impacts on the Agency's financial condition or funds available to the Agency for repayment of the Covered Bonds. Nor can the Agency predict the potential impacts on IPP Renewed of the recently proposed Decommissioned Asset Disposition Amendments. The Agency will continue to assess the impacts of the new and proposed legislation on the Agency and the Project and plans to continue to take actions that the Agency believes are most likely to result in timely repayment of the Covered Bonds.

2. ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

The third and fourth paragraphs under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – NOx Emissions" in the Agency's Annual Filing are replaced in their entirety by the following:

On April 15, 2024, EPA proposed to retain the existing secondary NAAQS for NOx. Pursuant to a consent decree between EPA, the Center for Biological Diversity, and the Center for Environmental Health, EPA is required to take final action on the rule by December 10, 2024.

On October 28, 2024, the U.S. District Court for the Northern District of California approved a consent decree between EPA and environmental plaintiffs including the Center for Biological Diversity, Sierra Club and the Center for Environmental Health, that would require EPA to complete a review of the primary NOx NAAQS and issue any resulting revisions of the standard by November 10, 2028.

The seventh paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Regional Haze" in the Agency Annual Filing is replaced in its entirety by the following:

On November 22, 2024, EPA finalized its partial approval and partial disapproval of the Utah SIP in substantially the form of its August 18, 2024 proposal. The Agency is continuing to assess the potential impact on IPP of EPA's action with respect to the Utah SIP.

The fourth paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Regulation of Greenhouse Gases—Federal and California Greenhouse Gas Initiatives" in the 2023 Annual Filing is replaced in its entirety by the following:

State and industry parties are currently challenging the final rule in the D.C. Circuit Court of Appeals with oral argument scheduled for December 6, 2024. On July 19, 2024, the D.C. Circuit denied a request for a stay on the final rule. The plaintiffs petitioned the U.S. Supreme Court to stay the rule, but the Court denied the petition on October 16, 2024. Despite denying the stay request, two of the Justices stated that the applicants have shown a strong likelihood of success on the merits.

APPENDIX C

SUMMARY OF CERTAIN DOCUMENTS

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SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE

The following is a summary of certain provisions of the Senior Indenture. This summary is not to be considered a full statement of the terms of the Senior Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Senior Indenture. No Senior Bonds are currently outstanding.

Definitions

Adjusted Aggregate Debt Service means, as of any date of calculation and with respect to any period, the sum of (i) the sum of the amounts of Adjusted Debt Service during such period for all Series of Senior Bonds and (ii) the Aggregate Debt Service during such period for all Series of Senior Bonds not included in the computation of Adjusted Debt Service on such date of calculation; provided, however, that in computing such Aggregate Debt Service any particular Lender Bonds shall be deemed to bear at all times to the maturity thereof the Assumed Interest Rate applicable thereto.

Adjusted Debt Service means, with respect to any Series of Senior Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Senior Bonds for such period which would result if the Principal Installment for such Series due on the final maturity date of such Series were adjusted over the period specified pursuant to the next sentence so that the Senior Bonds of such Series would have Substantially Equal Debt Service (as defined below) for each Fiscal Year of such period and so that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal of and premium, if any, and interest on the Senior Bonds of such Series in accordance with such adjustments and computing the interest component of Debt Service on the basis of the true interest cost actually incurred on such Series of Senior Bonds (determined by the true, actuarial method of calculation). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on a date which shall be specified in the Supplemental Indenture of Trust authorizing such Series of Senior Bonds, which date shall be not later than the earlier to occur of (i) 35 years after the date of such Senior Bonds or (ii) the termination date of the Transmission Service Contracts. For purposes of computing such true interest cost for any Series of Senior Bonds containing Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.

Assumed Interest Rate means, as to any Lender Bonds with a Variable Interest Rate, the interest rate for such Senior Bonds assumed for purposes of determining their maturity schedule, and as to any Lender Bonds not having a Variable Interest Rate, the stated interest rate for each such Lender Bond.

Cap Agreement means any financial arrangement which has been designated in writing to the Senior Indenture Trustee by an Authorized Authority Representative as a Cap Agreement under the Senior Indenture.

Debt Service Reserve Requirement means $0.

Lender Bonds mean Bonds which: (i) are issued in exchange for Notes, (ii) are issued pursuant to requirements of a lending or credit facility or agreement, and (iii) will be held by a bank, trust company or similar financial institution, domestic or foreign.

Notes shall mean notes or other evidences of indebtedness referred to in, and complying with specified provisions of, the Senior Indenture.

Series means all of the Bonds authenticated and delivered on original issuance and identified pursuant to the Senior Indenture or the Supplemental Indenture of Trust authorizing such Bonds as a separate Series of Bonds, and any Bonds thereafter authenticated and delivered in lieu of or in substitution for such Bonds pursuant to the Senior Indenture, regardless of variations in maturity, interest rate, sinking fund installments, or other provisions.

Substantially Equal Adjusted Aggregate Debt Service means, with respect to any period of similar Fiscal Years for all Series of Senior Bonds, that the greatest Adjusted Aggregate Debt Service for any Fiscal Year in such period is not in excess of one hundred and twenty-five percent (125%) of the Adjusted Aggregate Debt Service for any preceding Fiscal Year in such period.

Substantially Equal Debt Service means, with respect to any period of Years for any Series of Senior Bonds, that the greatest Debt Service for any Year in such period is not in excess of one hundred and twenty-five percent (125%) of the smallest Debt Service for any Year in such period; provided, however, that in computing Debt Service for the purpose of this definition, any particular Lender Bond shall be deemed to bear at all times prior to maturity thereof the Assumed Interest Rate applicable thereto.

Pledge Effected by the Senior Indenture

Under the Senior Indenture, the Authority has pledged and assigned to the Senior Indenture Trustee, for the benefit of the Holders of the Senior Bonds (the "Senior Bondholders"), (1) the proceeds of the sale of the Senior Bonds, (2) the Revenues, and (3) all Funds established by the Senior Indenture including the investments, if any, thereof, subject only to the provisions of the Senior Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Senior Indenture (including application of the moneys on deposit in the escrow funds established under the Senior Indenture).

Application of Revenues

Revenues are pledged by the Senior Indenture to payment of the principal and Redemption Price of, and interest on, the Senior Bonds, subject to the provisions of the Senior Indenture permitting application for other purposes. The Senior Indenture establishes the following Funds and Accounts for the application of Revenues:

Funds	Held By
Construction Fund	Senior Indenture Trustee
Revenue Fund	Senior Indenture Trustee
Operating Fund	Senior Indenture Trustee
Debt Service Fund	Senior Indenture Trustee
- Debt Service Account	
- Debt Service Reserve Account*	
Bond Anticipation Note Fund	Senior Indenture Trustee
Reserve and Contingency Fund	Senior Indenture Trustee
- Renewal and Replacement Account	
- Reserve Account	
General Reserve Fund	Senior Indenture Trustee

* The Senior Indenture was amended in April 2001, with the consent of Holders of the Senior Bonds, to eliminate the Debt Service Reserve Requirement for the Senior Bonds.

All Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

1. To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for Authority Operating Expenses or as a reserve for working capital, is equal to the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month. Such sum shall be paid to the Operating Fund as soon as practicable in each month after deposit of Revenues in the Revenue Fund, but not later than the last business day of such month. In addition, if the Supplemental Indenture authorizing a Series of Senior Bonds so provides, amounts from the proceeds of such Bonds may be deposited in the Operating Fund and set aside as a reserve for working capital. At the requisition of the Authority, signed by two Authorized Authority Representatives, amounts in the Operating Funds shall be paid out from time to time by the Senior Indenture Trustee for reasonable and necessary Authority Operating Expenses. Additional amounts may be paid out from the Operating Fund to establish a revolving fund with a maximum balance of $250,000 for the payment of Authority Operating Expenses not conveniently paid as described in the previous sentence. The Senior Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiencies in certain other funds established under the Senior Indenture with any balance to be deposited in the General Reserve Fund.

2. To the Debt Service Account in the Debt Service Fund, the amount required so that the balance in such Account equals the Accrued Aggregate Debt Service. The Senior Indenture Trustee shall apply amounts in the Debt Service Account to the payment of principal of and interest on the Senior Bonds; provided, however, that the interest coming due with respect to any Series of Senior Bonds may be payable by the Senior Indenture Trustee in such other manner as the Supplemental Indenture of Trust authorizing such Series of Senior Bonds shall specify. In addition, the Senior Indenture Trustee may, and if directed by the Authority must, apply certain amounts in the Debt Service Account to the purchase or redemption of Senior Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Senior Indenture Trustee must pay out of the Debt Service Account the amount required for the redemption of Senior Bonds called for redemption pursuant to sinking fund requirements, or the amount maturing on any redemption or maturity date.

In the event of the refunding of one or more Series of Senior Bonds, the Senior Indenture Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the Debt Service Account in the Debt Service Fund amounts accumulated therein with respect to Debt Service on the Senior Bonds being refunded and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on the Series of Senior Bonds being refunded; provided that such withdrawal shall not be made unless: (1) immediately thereafter the Series of Senior Bonds being refunded shall be deemed to have been paid pursuant to the Senior Indenture; and (2) the amount remaining in the Debt Service Account after such withdrawal shall not be less than the requirement of such Account pursuant to the Senior Indenture.

3. To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund together with the amount on deposit in any fund established pursuant to the proceedings authorizing the Notes and lawfully available to pay interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month shall equal all interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Senior Indenture Trustee shall apply amounts in the Bond Anticipation Note Fund to the payment of interest on Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Notes. However, if at any time the amounts in the Debt Service Account are less than the amounts required by the Senior Indenture, and there is not on deposit in the General Reserve Fund or in the Renewal and Replacement Account or the Reserve Account in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Senior Indenture Trustee shall transfer from the Bond Anticipation Note Fund the amount necessary to make up such deficiency.

4. To the Reserve and Contingency Fund, for credit to: (a) the Renewal and Replacement Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget; and (b) the Reserve Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget.

Amounts in the Renewal and Replacement Account shall be applied to the Cost of Acquisition of Capacity relating to any Capital Improvements.

To the extent not provided for in the then current Annual Budget or by reserves in the Operating Fund or from the proceeds of Senior Bonds, amounts in the Reserve Account shall be applied to the payment of extraordinary operation and maintenance costs and contingencies of the Transmission Project. No payments shall be made from the Reserve and Contingency Fund if and to the extent that the proceeds of insurance, including the proceeds of any self-insurance fund, or other moneys recoverable as the result of damage, if any, are available to pay the costs otherwise payable from the Reserve and Contingency Fund.

If at any time the amounts in the Debt Service Account are less than the amounts required by the Senior Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Senior Indenture Trustee shall transfer from the Reserve Account and the Renewal and Replacement Account, in that order, the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account or in the Reserve Account not required to meet any deficiencies in the Debt Service Fund or for any of the purposes for which such Accounts were established shall be transferred to the Operating Fund to the extent, if any, deemed necessary by the Authority, to make up any deficiencies therein. Any remaining excess shall be deposited into the General Reserve Fund.

5. To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Authority must transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts; and (b) to the Renewal and Replacement Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts.

Deposits from the Revenue Fund into the Debt Service Fund, the Bond Anticipation Note Fund, the Reserve and Contingency Fund and the General Reserve Fund shall be made as soon as practicable in each month after the deposit of Revenues into the Revenue Fund and the payment to the Operating Fund have been made for such month, but not later than the last business day of such month.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above or not required by the Senior Indenture for the purchase or redemption of Senior Bonds or not required to be transferred to the 2025 Series A Pledged Revenues Account pursuant to the 2025 Series A Subordinated Indenture, will, upon determination of the Authority, be applied to or set aside for any one or more of the following: (i) payment into the Revenue Fund; (ii) the purchase or redemption of any Senior Bonds, and expenses and reserves in connection therewith; (iii) Authority Operating Expenses or reserves therefor; (iv) payments into any separate account or accounts established in the Construction Fund; (v) Cost of Acquisition of Capacity attributable to Capital Improvements or reserves therefor; (vi) reduction of the monthly transmission costs of the Project Participants under the Transmission Service Contracts; (vii) payment of principal of Notes; and (viii) any other lawful purpose of the Authority related to the Transmission Project or the Authority Capacity. Senior Bonds purchased or redeemed with amounts in the General Reserve Fund shall be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Certain Requirements of and Conditions to Issuance of Senior Bonds

Senior Bonds shall be authenticated by the Senior Indenture Trustee pursuant to the Senior Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Senior Indenture Trustee shall have received an Opinion of Bond Counsel to the effect that the Senior Bonds of the Series being issued have been duly and validly authorized and issued and are valid and binding obligations of the Authority and as to certain other matters concerning the Senior Indenture.

(b) Except in the case of Lender Bonds and Refunding Bonds, the Authority shall have certified that it is not in default in the performance of its agreements under the Senior Indenture.

The Senior Indenture also provides that Principal Installments shall be established at the time of issuance for each Series of Senior Bonds and each Series of Additional Bonds and Refunding Bonds so as to comply with the following:

(a) Such Principal Installment shall commence not later than the later of (i) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Senior Bonds or (ii) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which the Authority estimates that the Initial Facilities will first reach their Date of Firm Operation and shall terminate not later than the date on which the Transmission Service Contracts terminate.

(b) Such Principal Installments shall result in either (i) Substantially Equal Debt Service for the Senior Bonds of such Series for the Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the Initial Facilities and for each Year thereafter to and including the final maturity date of such Series or (ii) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Senior Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Senior Bonds then Outstanding, including such Series being issued, beginning, however, no earlier than the Fiscal Year immediately preceding the due date of the first Principal Installment to occur subsequent to the Date of Firm Operation of the Initial Facilities, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Senior Bonds Outstanding immediately prior to the issuance of such Series being issued or the Fiscal Year immediately preceding the latest maturity of such Series being issued, whichever is earlier (using in the case of any Series of Senior Bonds sold by competitive bidding a net effective interest rate for the Senior Bonds of such Series as estimated by the Authority); provided, that, if the first Principal Installment for any Series of Senior Bonds shall be less than twelve (12) months after the date of issuance thereof, it shall be assumed, for purposes of this calculation, that interest accrued on such Series for the entire 12-month period preceding the first Principal Installment at the same rate as interest accrued for the actual portion of such period during which such Series of Senior Bonds was Outstanding.

Additional Bonds

The Authority may issue one or more Series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition of Capacity relating to any Capital Improvements.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund any Outstanding Senior Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Senior Indenture Trustee pursuant to the Senior Indenture upon compliance with certain requirements and conditions, including the receipt by the Senior Indenture Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Senior Bonds to be redeemed plus the amount required to pay principal on refunded Senior Bonds not to be redeemed together with accrued interest on such Senior Bonds to the redemption date or maturity date, as the case may be, or (ii) Investment Securities in such amounts and having such terms as required by the Senior Indenture to pay the principal or Redemption Price, if applicable, and interest due on the redemption date or maturity date, as the case may be.

Investment of Certain Funds and Accounts

The Senior Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account in the Debt Service Fund and in the case of the Bond Anticipation Note Fund, subject to the terms of agreements relating to the issuance of Notes, shall, be invested and re-invested to the fullest extent practicable in Investment Securities. The Senior Indenture provides that such investments and re-investments will mature no later than such times as are necessary to provide moneys when needed for payments from such Funds and Accounts and provides specific limitations on the term of investments for moneys in certain Funds and Accounts.

Interest (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 such Funds or Accounts, other than the Construction Fund, shall be paid into the Revenue Fund except that interest shall be paid into the Construction Fund to the extent provided in the Supplemental Indenture of Trust authorizing any Series of Senior Bonds issued under the Senior Indenture. Interest earned on any moneys or investments in each separate account in the Construction Fund shall be held in such account for the purposes thereof.

The Senior Indenture Trustee may deposit moneys in all Funds and Accounts held under the Senior Indenture in banks or trust companies organized under the laws of any state of the United States or national banking associations ("Depositaries"). All moneys held under the Senior Indenture by the Senior Indenture Trustee or any Depositary must be (1) either (a) continuously and fully insured by the Federal Deposit Insurance Corporation, or (b) continuously and fully secured by depositing with the Senior Indenture Trustee or any Federal Reserve Bank, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive, of the definition of "Investment Securities" in the Senior Indenture having a market value (exclusive of accrued interest) not less than the amount of such moneys, and (2) held in such other manner as may then be required by applicable federal or State of California laws and regulations and applicable state laws and regulations of the state in which the Trustee or such Depositary is located, regarding security for the deposit of trust funds; provided, however, that it shall not be necessary for the Senior Indenture Trustee or any Paying Agent to give security for the deposit of any moneys held in trust by it and set aside for the payment of principal or Redemption Price of or interest on any Senior Bonds or to give security for any moneys which shall be represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Senior Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized cost of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest. Such computations shall be determined as of July 1 in each year.

Rate Covenant

The Authority covenants in the Senior Indenture as long as any Senior Bonds are Outstanding it will have good right and lawful power to establish and collect rates and charges with respect to the use of Authority Capacity, subject to the terms of the Transmission Service Contracts. The Authority covenants in the Senior Indenture that it shall at all times establish and collect rates and charges for the use of Authority Capacity which provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all of the following:

(a) Authority Operating Expenses during such Fiscal Year;

(b) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(c) The amount, if any, to be paid during such Fiscal Year into the Bond Anticipation Note Fund;

(d) The amount to be paid during such Fiscal Year into the Reserve and Contingency Fund for credit to the Renewal and Replacement Account, and the Reserve Account therein; and

(e) All other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

The Authority will not furnish or supply or cause to be furnished or supplied any use or service of Authority Capacity free of charge to any person, firm or corporation, public or private, and the Authority will, subject to the Senior Indenture and consistent with the Transmission Project Agreements, and upon the direction of the Senior Indenture Trustee, enforce the payment of any and all accounts owing to the Authority by reason of Authority Capacity by discontinuing such use or service, or by filing suit therefor, as soon as practicable ninety (90) days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Transmission Service Contracts and Transmission Project Agreements

The Senior Indenture Trustee covenants that it shall receive and deposit in the Revenue Fund all amounts payable to it under the Transmission Service Contracts or otherwise payable to it pursuant to any contract for use of Authority Capacity or any part thereof. The Authority shall enforce the provisions of the Transmission Service Contracts and duly perform its covenants and agreements thereunder, and will not consent or agree to or permit any rescission of or amendment to, or otherwise take any action under or in connection with, the Transmission Service Contracts which would reduce the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of Bondholders under the Senior Indenture; however, the Authority is not thereby prohibited from amending any Transmission Service Contracts.

The Authority shall enforce the provisions of the Transmission Project Agreements and duly perform its covenants and agreements thereunder. The Authority will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Transmission Project Agreements which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Bondholders under the Senior Indenture; however, the Authority is not thereby prohibited from amending or taking other action in connection with any Transmission Service Contracts, Southern Transmission System Agreement, Power Sales Contract or Intermountain Power Agency's Bond Resolution.

Insurance

The Authority shall, at all times after it shall acquire Authority Capacity, insure Authority Capacity from such causes customarily insured against and in such amounts as are usually obtained. The Authority shall also use its best efforts to maintain or cause to be maintained any additional or other insurance which the Authority deems necessary or advisable to protect its interests and those of the Senior Bondholders. If any useful portion of the Transmission Project is damaged or destroyed, the Authority shall diligently prosecute the reconstruction or replacement thereof. The proceeds of any insurance, including the proceeds of any self-insurance fund, paid on account of damage or destruction (other than any business interruption loss insurance) shall be held by the Senior Indenture Trustee and applied, to the extent necessary, to the Cost of Acquisition of Capacity. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund.

Events of Default and Remedies

Events of Default specified in the Senior Indenture include failure to pay principal or Redemption Price of any Senior Bond when due; failure to pay any interest installment on any Senior Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; and default for one hundred and twenty (120) days after written notice thereof from the Senior Indenture Trustee or the Holders of not less than ten percent (10%) in principal amount of Senior Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Senior Indenture or in the Senior Bonds. Upon the happening of any such Event of Default the Senior Indenture Trustee or the Holders of not less than twenty-five percent (25%) in principal amount of the Senior Bonds then Outstanding may declare the principal of and accrued interest on all Senior Bonds then Outstanding due and payable immediately (subject to a rescission of such declaration upon the curing of such default before the Senior Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, the Authority shall, if demanded by the Senior Indenture Trustee, (1) account, as if it were the trustee of an express trust, for all Revenues and other moneys, securities and funds pledged or held under the Senior Indenture, and (2) cause to be paid over to the Senior Indenture Trustee (a) forthwith, all moneys, securities and funds held by the Authority in any Fund under the Senior Indenture and (b) as received, all Revenues. The Senior Indenture Trustee shall apply all moneys, securities, funds and Revenues received during the continuance of an Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Senior Indenture Trustee and Paying Agents; (2) to the payment of Authority Operating Expenses; and (3) to the payment of interest and principal or Redemption Price then due on the Senior Bonds without preference or priority of interest over principal or principal over interest, unless the principal of all Senior Bonds has not been declared due and payable, in which case first to the payment of interest and second to the payment of principal or Redemption Price on those Senior Bonds which have become due and payable in order of their due dates, and if the amount available for such payment shall not be sufficient to pay such amounts in full, then to the payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Senior Indenture Trustee shall have the right to apply in an appropriate proceeding for appointment of a receiver of Authority Capacity.

If an Event of Default has occurred and has not been remedied the Senior Indenture Trustee may, and on request of the Holders of not less than twenty-five percent (25%) in principal amount of Senior Bonds Outstanding shall, proceed to protect and enforce its rights and the rights of the Senior Bondholders under the Senior Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Senior Indenture or in aid of the execution of any power granted in the Senior Indenture or any remedy granted under the Act, or for an accounting against the Authority as if it were the trustee of an express trust, or in the enforcement of any other legal or equitable right, as the Senior Indenture Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Senior Indenture. The Senior Indenture Trustee may, and upon the request of the Holders of a majority in principal amount of the Senior Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Senior Indenture or to preserve or protect the interests of the Senior Indenture Trustee and of the Senior Bondholders.

No Senior Bondholder shall have any right to institute any suit, action or proceeding for the enforcement of any provision of the Senior Indenture or the execution of any trust under the Senior Indenture or for any remedy under the Senior Indenture, unless (1) such Senior Bondholder previously has given the Senior Indenture Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Senior Bonds then Outstanding have filed a written request with the Senior Indenture Trustee and have offered the Senior Indenture Trustee a reasonable opportunity to exercise its powers or to institute such suit, action or proceeding, and (3) there have been offered to the Senior Indenture Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and the Senior Indenture Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Senior Indenture provides that nothing therein or in the Senior Bonds affects or impairs the Authority’s obligations to pay the principal or

Redemption Price, if any, of the Senior Bonds and interest thereon when due or the right of any Senior Bondholder to enforce such payment of his or her Senior Bonds.

The Holders of not less than a majority in principal amount of Senior Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Senior Indenture Trustee, or exercising any trust or power conferred upon the Senior Indenture Trustee, subject to the Senior Indenture Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Senior Indenture Trustee in personal liability or would be unjustly prejudicial to Senior Bondholders not parties to such direction.

SUMMARY OF CERTAIN PROVISIONS OF THE 2025 SERIES A SUBORDINATED INDENTURE

The following is a summary of certain provisions of the 2025 Series A Subordinated Indenture. This summary is not to be considered a full statement of the terms of the 2025 Series A Subordinated Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the 2025 Series A Subordinated Indenture.

Certain Definitions

Available Revenues shall have the meaning ascribed thereto in the Senior Indenture.

Bondowner or *Owner* shall mean each person or entity who is the registered owner of any 2025 Series A Subordinate Bond or Bonds.

Business Day shall mean a day (a) other than a Saturday, a Sunday or any other day on which banks located in the city in which the principal office of the Trustee or the Paying Agent is located, are required or authorized by law to close, and (b) on which the New York Stock Exchange is not closed.

Debt Service shall mean, with respect to any period, an amount equal to the sum of (i) interest accruing during such period on the Outstanding 2025 Series A Subordinate Bonds, and (ii) that portion of each Principal Installment of the Outstanding 2025 Series A Subordinate Bonds that would become due during such period if such Principal Installment were deemed to become due daily in equal amounts from the next preceding Principal Installment due date for the 2025 Series A Subordinate Bonds (or, if there shall be no such preceding Principal Installment due date, from a date one year preceding the due date of such Principal Installment or the date of initial issuance and delivery of the 2025 Series A Subordinate Bonds, whichever is later). Such interest and Principal Installment for the 2025 Series A Subordinate Bonds shall be calculated on the assumption that no 2025 Series A Subordinate Bonds Outstanding on the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof.

Defeasance Obligations shall mean (i) non-callable, direct obligations of the United States of America, obligations fully and unconditionally guaranteed as to payment of principal and interest by the United States of America including, but not limited to, the interest components of Resolution Funding Corporation securities and obligations of the United States Agency for International Development, as well as non-callable, senior debt obligations of the Federal National Mortgage Association, the Federal Home Loan Mortgage Corporation, the Federal Home Loan Bank System and the Federal Farm Credit System (collectively, "Government Obligations"); or (ii) any bonds or other obligations of any state of the United States of America or of any agency, instrumentality or local governmental unit of any such state which are not callable at the option of the obligor prior to maturity or as to which irrevocable instructions have been given by the obligor to call on the date specified in the notice and (a) rated no lower than the then-current rating on direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America (or by an agency thereof to the extent such obligations are backed by the full faith and credit of the United States of America), or (b)(1) which are fully secured as to principal and interest and redemption premium, if any, by a fund consisting only of cash and/or Government Obligations, which fund may be applied only to the payment of such principal of and interest and redemption premium, if any, on such bonds or other obligations on the maturity date or dates thereof or the specified redemption date or dates pursuant to such irrevocable instructions, as appropriate, and (2) which fund is sufficient, as verified by a nationally recognized independent certified public accountant or independent arbitrage consultant, to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this clause (ii) on the maturity date or dates thereof or on the redemption date or dates specified in the irrevocable instructions referred to above, as appropriate.

Investment Securities shall mean and include: (i) any of the securities that are at the time of purchase legal for investment of the Authority's funds under applicable law (including California Government Code Sections 53601 and 53635); (ii) investment agreements (including, but not limited to, guaranteed investment contracts, repurchase agreements, forward purchase agreements and reserve fund put agreements) with a domestic or foreign bank or corporation (other than a life or property casualty insurance company) the long-term debt of which, or, in the case of a monoline financial guaranty insurance company, claims paying ability of the guaranty for which, is rated at the time of execution of such investment agreement 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 or at such lower rating as permitted by the then current investment policies of the Authority; or (iii) other forms of investment for which confirmation is received from each Rating Agency then rating any of the 2025 Series A Subordinate Bonds that such investment will not adversely affect such Rating Agency's rating on such 2025 Series A Subordinate Bonds.

Issue Date shall mean the date of original issuance of the 2025 Series A Subordinate Bonds.

Opinion of Bond Counsel shall mean an opinion signed by Bond Counsel.

Outstanding, when used with reference to 2025 Series A Subordinate Bonds, shall mean, as of any date, 2025 Series A Subordinate Bonds theretofore or thereupon being authenticated and delivered under the 2025 Series A Subordinated Indenture except for:

(i) 2025 Series A Subordinate Bonds cancelled by the Trustee on or prior to such date;

(ii) if applicable, 2025 Series A Subordinate Bonds (or portions of 2025 Series A Subordinate Bonds) for the payment or redemption of which moneys, equal to the principal amount or Redemption Price thereof, as the case may be, with interest, if any, to the date of maturity or redemption date, shall be held in trust under the 2025 Series A Subordinated Indenture and set aside for such payment or redemption (whether at or prior to the maturity or redemption date), provided that if such 2025 Series A Subordinate Bonds (or portions of 2025 Series A Subordinate Bonds) are to be redeemed, notice of such redemption shall have been given as provided in the 2025 Series A Subordinated Indenture or provision satisfactory to the Trustee shall have been made for the giving of such notice;

(iii) 2025 Series A Subordinate Bonds in lieu of or in substitution for which other 2025 Series A Subordinate Bonds shall have been authenticated and delivered pursuant to the 2025 Series A Subordinated Indenture; and

(iv) 2025 Series A Subordinate Bonds deemed to have been paid as provided in the 2025 Series A Subordinated Indenture.

Parity Swap shall mean any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement (including all confirmations, schedules, exhibits, attachments, appendices and other documentation attached to such agreement or forming a part thereof or incorporated therein) (a) that is entered into by the Authority and a Parity Swap Provider (and, if applicable, the Trustee), (b) that is permitted to be entered into by the Authority under the laws of the State of California applicable thereto at the time the Authority enters into such agreement, as evidenced by an opinion of counsel acceptable to the Authority, (c) as to which the documentation thereof provides that payments to be made by the Authority pursuant to such agreement (other than termination payments thereunder, which shall be payable on a basis subordinate and junior to the payments to be made on the 2025 Series A Subordinate Bonds and any other payments due on the Parity Swap) constitute obligations payable on a parity basis with the payments to be made on the 2025 Series A Subordinate Bonds as and to the extent provided in the 2025 Series A Subordinated Indenture and (d) designated in writing to the Trustee by an Authorized Authority Representative as a Parity Swap under the 2025 Series A Subordinated Indenture.

Parity Swap Provider shall mean, with respect to each Parity Swap, the entity (other than the Authority and, if applicable, the Trustee) that is a party thereto, and its permitted successors and assigns, whose public credit ratings, or whose obligations under a Parity Swap are guaranteed by a financial institution whose public credit ratings, are (at the time the applicable Parity Swap is entered into), unless otherwise approved by the Authority, in not lower than the second highest rating category (without regard to gradations within such category) by any two nationally-recognized credit rating agencies.

Pledged Revenues shall mean all Available Revenues transferred to and deposited in the 2025 Series A Pledged Revenues Account pursuant to the Senior Indenture (including the Thirty-First Supplemental Indenture).

Principal Installment shall mean, as of any date of calculation, so long as any 2025 Series A Subordinate Bond is Outstanding, (i) the principal amount of the 2025 Series A Subordinate Bonds due on a certain future date for which no Sinking Fund Installments have been established, or (ii) if applicable, the unsatisfied balance of any Sinking Fund Installments due on a certain future date for the 2025 Series A Subordinate Bonds, plus the amount of the sinking fund redemption premiums, if any, that would be payable upon redemption of such 2025 Series A Subordinate Bonds on such future date in a principal amount equal to said unsatisfied balance of such Sinking Fund Installments, or (iii) if such future dates coincide as to different 2025 Series A Subordinate Bonds, the sum of such principal amount of 2025 Series A Subordinate Bonds and of such unsatisfied balance of Sinking Fund Installments due on such future date plus such applicable redemption premiums, if any.

Reserve Account Policy shall mean any surety bond, insurance policy, line of credit, letter of credit or similar instrument issued to the Trustee by a company 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 Bonds to which it relates (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.

Reserve Requirement shall mean an amount equal to $0.00.

Securities Depository shall mean The Depository Trust Company and its successors and assigns or if (i) the then Securities Depository resigns from its functions as depository of the 2025 Series A Subordinate Bonds or (ii) the Authority discontinues use of the then Securities Depository pursuant to the 2025 Series A Subordinated Indenture, any other securities depository which agrees to follow the procedures required to be followed by a securities depository in connection with the 2025 Series A Subordinate Bonds and which is selected by the Authority.

Thirty-First Supplemental Indenture shall mean the Thirty-First Supplemental Indenture, dated as of [____] 1, 2025, as supplemented or amended from time to time, from the Authority to U.S. Bank Trust Company, National Association, as trustee, amending and supplementing the Senior Indenture as theretofore in effect.

2025 Series A Accrued Debt Service shall mean, as of any date of calculation, an amount equal to the amount of accrued Debt Service, calculating the accrued Debt Service as an amount equal to the sum of (i) interest on the 2025 Series A Subordinate Bonds accrued and unpaid and to accrue to the end of the then current calendar month, and (ii) Principal Installments on the 2025 Series A Subordinate Bonds due and unpaid and that portion of the Principal Installment on the 2025 Series A Subordinate Bonds that is to become due (if deemed to accrue in the manner set forth in the definition of Debt Service) by the end of such calendar month. For purposes of this definition, interest shall accrue with respect to each month of any Fiscal Year based on the total amount of interest payable on the January 1 included in such Fiscal Year and the next succeeding July 1, divided by twelve (12).

2025 Series A Subordinate Bonds shall mean the Authority's Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project), authenticated and delivered under and pursuant to the 2025 Series A Subordinated Indenture.

2025 Series A Subordinated Indenture shall mean the Indenture of Trust relating to the 2025 Series A Subordinate Bonds, dated as of [____] 1, 2025, from the Authority to U.S. Bank Trust Company, National Association, as trustee, as supplemented and amended from time to time.

Pledge Effected by the 2025 Series A Subordinated Indenture

Under the 2025 Series A Subordinated Indenture, the Authority has pledged and assigned to the Trustee, for the benefit of the owners of the 2025 Series A Subordinate Bonds and any Parity Swap Providers, (1) the Pledged Revenues and (2) the 2025 Series A Issue Fund and all Accounts therein established by the 2025 Series A Subordinated Indenture; subject only to the provisions of the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture, respectively, as security for (i) the payment of the 2025 Series A Subordinate Bonds, the interest thereon and premium, if any, with respect thereto, (ii) as security for the payment obligations of the Authority under any Parity Swaps and (iii) as security for the performance of any other obligations of the Authority under the 2025 Series A Subordinated Indenture, all in accordance with the provisions of the 2025 Series A Subordinate Bonds, the 2025 Series A Subordinated Indenture, the Thirty-First Supplemental Indenture and any Parity Swaps. The 2025 Series A Subordinate Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or Redemption Price (if applicable) thereof, and interest thereon, in accordance with their terms and the provisions of the 2025 Series A Subordinated Indenture and the Thirty-First Supplemental Indenture solely by the moneys, Fund and Accounts set forth in the 2025 Series A Subordinated Indenture. The pledge made in the 2025 Series A Subordinated Indenture with respect to the 2025 Series A Subordinate Bonds and any Parity Swaps is valid and binding upon delivery of the 2025 Series A Subordinate Bonds, and the Pledged Revenues and the 2025 Series A Issue

Fund shall immediately be subject to the applicable lien of such pledge without any physical delivery thereof or any further act, and the lien of such pledge shall be valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the Authority irrespective of whether such parties have notice thereof. The 2025 Series A Subordinate Bonds and any Parity Swaps shall not be deemed to be Bonds as defined in the Senior Indenture.

Nature of Obligation

The 2025 Series A Subordinate Bonds are not an obligation of the State of California or any public agency thereof, other than the Authority, or any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of the State of California or any public agency thereof nor any member of the Authority nor any Project Participant is pledged for the payment of the principal or Redemption Price of, or interest on, the 2025 Series A Subordinate Bonds or the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. The 2025 Series A Subordinate Bonds and any Parity Swaps shall never constitute the debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution of the State of California or statutes of the State of California, nor shall they constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit.

Application of Pledged Revenues

Pledged Revenues are pledged by the 2025 Series A Subordinated Indenture to payment of the principal and Redemption Price of, and interest on, the 2025 Series A Subordinate Bonds and for payment of the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. The 2025 Series A Subordinated Indenture establishes the 2025 Series A Issue Fund and the following Accounts therein, to be held by the Trustee for the deposit and application of Pledged Revenues:

– 2025 Series A Pledged Revenues Account

– 2025 Series A Payment Account

– 2025 Series A Reserve Account

– 2025 Series A Charges Account

– 2025 Series A Remainder Account

– 2025 Series A Costs of Issuance Account

The Trustee may, with the prior written consent of the Authority, establish additional accounts or subaccounts within the 2025 Series A Issue Fund or any of the Accounts therein, respectively, if the Trustee determines that such additional accounts or subaccounts would be advantageous or desirable.

Amounts deposited in the 2025 Series A Costs of Issuance Account shall be expended from time to time to pay Costs of Issuance relating to the 2025 Series A Subordinate Bonds upon receipt by the Trustee of a requisition or other written directions signed by an Authorized Authority Representative. If any amount shall remain in the 2025 Series A Costs of Issuance Account when all Costs of Issuance have been paid, as stated in a certificate of an Authorized Authority Representative, such amount shall be transferred to the 2025 Series A Remainder Account or if no such certificate is received, then one hundred eighty (180) days after the Issue Date of the 2025 Series A Subordinate Bonds the Trustee shall make such transfer.

All Pledged Revenues are to be deposited promptly in the 2025 Series A Pledged Revenues Account upon receipt thereof. Amounts in the 2025 Series A Pledged Revenues Account are to be paid as soon as practicable in each month after their deposit, but in any case, no later than 12:00 noon, New York

City time, on the last Business Day of the month, in the following order of priority for application therefrom as follows:

1. To the 2025 Series A Payment Account, the amount, if any, required so that the balance in said Account shall equal the sum of (A) the 2025 Series A Accrued Debt Service as of the last day of the then current month, and (B) all amounts due and payable by the Authority under any Parity Swaps during such month (or the entire amount transferred by the Trustee from the 2025 Series A Pledged Revenues Account if less than the required amount).

The Trustee shall pay out of the 2025 Series A Payment Account, subject to the two immediately following paragraphs, without preference or priority of one transfer over the others (i) to the Paying Agent (a) on or before each Interest Payment Date the amount required for the interest payable on the 2025 Series A Subordinate Bonds on such date, (b) on or before each Principal Installment due date, the amount required for the Principal Installment payable on such due date, and (c) on or before any redemption date for the 2025 Series A Subordinate Bonds, the amount required for the payment of principal, premium, if any, and interest on the 2025 Series A Subordinate Bonds then to be redeemed; and (ii) to any Parity Swap Providers, any amounts due and payable by the Authority under the Parity Swaps during such month. Amounts so paid to the Paying Agent with respect to the 2025 Series A Subordinate Bonds shall be applied by the Paying Agent on and after the due dates thereof. The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable from the 2025 Series A Payment Account pursuant to clause (ii). Notwithstanding anything to the contrary in the 2025 Series A Subordinated Indenture, payments due to any Parity Swap Providers during a given month shall not be paid earlier in such month than the payment of any interest or Principal Installment due during such month.

All amounts held at any time in the 2025 Series A Payment Account shall be held until applied on a parity basis for the ratable security and payment of (i) 2025 Series A Accrued Debt Service and (ii) amounts due and payable by the Authority under any Parity Swaps, at any time in proportion to the amounts accrued or due and payable, as applicable.

In the event of the refunding of all or a portion of the 2025 Series A Subordinate Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the 2025 Series A Payment Account amounts accumulated therein with respect to Debt Service on the 2025 Series A Subordinate Bonds being refunded and, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, of and interest on the maturity or maturities of the 2025 Series A Subordinate Bonds being refunded; provided that such withdrawal shall not be made unless: (i) immediately thereafter the maturity or maturities of 2025 Series A Subordinate Bonds being refunded shall be deemed to have been paid pursuant to the 2025 Series A Subordinated Indenture; and (ii) the amount, if any, remaining in the 2025 Series A Payment Account after such withdrawal shall not be less than the requirement of such 2025 Series A Payment Account pursuant to the 2025 Series A Subordinated Indenture.

2. To the 2025 Series A Reserve Account, upon the occurrence of any deficiency therein (if applicable), (a) if the 2025 Series A Reserve Account is at that time funded by a Reserve Account Policy the provider of which has not failed to make payments thereunder, the amount of each unreplenished prior withdrawal from the 2025 Series A Reserve Account so that the provider of the Reserve Account Policy has been repaid for any draw made under such Reserve Account Policy for the 2025 Series A Reserve Account or (b) if the 2025 Series A Reserve Account is not at that time funded by a Reserve Account Policy or, if funded by a

Reserve Account Policy, the provider of such Reserve Account Policy has failed to make payment thereunder, the amount, if any, required for the 2025 Series A Reserve Account to equal the Reserve Requirement as of the last day of the then current month (or the entire amount so transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposit in numbered paragraph 1 above if less than the required amount). **Pursuant to the 2025 Series A Subordinated Indenture, the Reserve Requirement for the 2025 Series A Subordinate Bonds shall be equal to $0.00, and the 2025 Series A Reserve Account will not be funded.**

If at any time the amount in the 2025 Series A Payment Account shall be less than the amount required to be in such Account pursuant to numbered Paragraph 1 above, the Trustee shall transfer amounts (if any) from the 2025 Series A Reserve Account to the 2025 Series A Payment Account (or, if applicable, the Trustee shall draw on the Reserve Account Policy (if any) and deposit the proceeds thereof in the 2025 Series A Payment Account) to the extent necessary to make good the deficiency.

Whenever the moneys on deposit in the 2025 Series A Reserve Account shall exceed the Reserve Requirement for the 2025 Series A Subordinate Bonds, if any, such excess (to the extent not required to be transferred to the trustee for the Senior Bonds) shall be transferred to the 2025 Series A Pledged Revenues Account.

In the event of the refunding of all or any portion of the 2025 Series A Subordinate Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, transfer from the 2025 Series A Reserve Account any amounts accumulated therein and, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, and interest on the maturity or maturities of the 2025 Series A Subordinate Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the maturity or maturities of the 2025 Series A Subordinate Bonds being refunded shall be deemed to have been paid pursuant to the 2025 Series A Subordinated Indenture, and (b) the amount remaining in the 2025 Series A Reserve Account after such withdrawal shall not be less than the requirement of such 2025 Series A Reserve Account, if any, pursuant to the 2025 Series A Subordinated Indenture.

If a Reserve Account Policy shall be in full force and effect, any deposits required to be made with respect to the 2025 Series A Reserve Account pursuant to the 2025 Series A Subordinated Indenture shall include any amounts due to the provider of such Reserve Account Policy resulting from a draw on such Reserve Account Policy (which amounts shall constitute a "deficiency" or "withdrawal" from the 2025 Series A Reserve Account as provided in the 2025 Series A Subordinated Indenture). Any such amounts shall be paid to the provider of any Reserve Account Policy as provided in such Reserve Account Policy or any related agreement.

3. To the 2025 Series A Charges Account, the amount, if any, required so that the balance in said 2025 Series A Charges Account equals the sum of all amounts accrued or due and payable by the Authority as charges and fees to the Trustee or the Paying Agent during such month (or the entire amount transferred by the Trustee from the 2025 Series A Pledged Revenues Account after making the deposits in numbered paragraphs 1 and 2 above if less than the required amount).

The Trustee shall transfer moneys from the 2025 Series A Charges Account in the following amounts and in the following order of priority: (a) to the 2025 Series A Payment Account and the 2025 Series A Reserve Account the amount necessary (or all the moneys in the

2025 Series A Charges Account if less than the amount necessary) to make up any deficiencies in payments to the 2025 Series A Payment Account and the 2025 Series A Reserve Account required by numbered paragraphs 1 and 2 above, and (b) in the event of any transfer of moneys from the 2025 Series A Reserve Account to the 2025 Series A Payment Account, to the 2025 Series A Reserve Account the amount of the deficiency in such 2025 Series A Reserve Account resulting from such transfer.

The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable from the 2025 Series A Charges Account and the Trustee shall pay out of the 2025 Series A Charges Account to the Trustee and the Paying Agent, the amounts due and payable by the Authority as fees and charges to each of them for their charges and costs during such month.

4. To the 2025 Series A Remainder Account, the remaining balance, if any, in the 2025 Series A Pledged Revenues Account after making the deposits pursuant to numbered paragraphs 1, 2 and 3 above.

The Trustee shall transfer from the 2025 Series A Remainder Account the following amounts in the following order of priority: (i) to the 2025 Series A Payment Account and the 2025 Series A Reserve Account the amount necessary (or all the moneys in the 2025 Series A Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2025 Series A Payment Account and 2025 Series A Reserve Account required by numbered paragraphs 1 and 2 above; (ii) in the event of any transfer of moneys from the 2025 Series A Reserve Account to the 2025 Series A Payment Account, to the 2025 Series A Reserve Account the amount of the deficiency in such 2025 Series A Reserve Account resulting from such transfer, if any; and (iii) to the 2025 Series A Charges Account the amount necessary (or all the moneys in the 2025 Series A Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2025 Series A Charges Account required by numbered paragraph 3 above.

Amounts in the 2025 Series A Remainder Account not required to meet a deficiency described in the preceding paragraph and not required to be transferred to the trustee for the Senior Bonds pursuant to the 2025 Series A Subordinated Indenture will, upon determination of the Authority evidenced by a certificate of an Authorized Authority Representative delivered to the Trustee and after consultation with Bond Counsel, be applied to or set aside for any lawful purpose of the Authority related to the Transmission Project or the Authority Capacity.

Investment of Certain Accounts

The 2025 Series A Subordinated Indenture provides that moneys held in the 2025 Series A Issue Fund or any Account therein shall be invested and reinvested by the Trustee to the fullest extent practicable in Investment Securities that mature or are available not later than such times as shall be necessary to provide moneys when needed for payments to be made from the 2025 Series A Issue Fund or Accounts therein. The 2025 Series A Subordinated Indenture provides that amounts in the 2025 Series A Remainder Account shall be invested or reinvested in Investment Securities that mature or are available within five years from the date of such investment, and, in any case, the Investment Securities in the 2025 Series A Issue Fund and Accounts therein shall mature or be available no later than such times as are necessary to provide moneys when needed for payments from such Accounts.

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 2025 Series A Issue Fund and the Accounts established therein, shall, to the extent amounts in such Fund or Account exceeds the requirements for deposit therein and to the extent required by the Senior Indenture, be transferred to the trustee for the Senior Bonds for deposit in the Revenue Fund and to the extent not required to be transferred to the trustee for the Senior Bonds, be transferred to the 2025 Series A Pledged Revenues Account or as otherwise instructed by an Authorized Authority Representative.

In computing the amount in the 2025 Series A Issue Fund or any Account created under the 2025 Series A Subordinated Indenture, obligations purchased as an investment of moneys therein shall be valued at the greater of the cost of such obligations or the amortized value thereof, exclusive of accrued interest. Such computations shall be determined as of July 1 in each year.

Creation of Liens; Sale of Authority Capacity

Except as otherwise expressly provided in the 2025 Series A Subordinated Indenture, the Authority shall not issue any bonds, notes, debentures or other evidences of indebtedness of similar nature, other than the 2025 Series A Subordinate Bonds or Parity Swaps, payable out of or secured by a security interest in or a pledge or assignment of the Pledged Revenues or other moneys, securities or funds held or set aside by the Authority or by the Fiduciaries under the 2025 Series A Subordinated Indenture for the benefit of the Owners of the 2025 Series A Subordinate Bonds and for any Parity Swap Providers and shall not create or cause to be created any other lien or charge thereon; provided, however, that nothing in the 2025 Series A Subordinated Indenture shall preclude the issuance of any bonds, notes, debentures, evidences of indebtedness or the incurrence of any obligation (including, but not limited to, any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement) if same is payable on a basis subordinate and junior to the 2025 Series A Subordinate Bonds and the Parity Swaps, if any, and secured by a lien or charge on Pledged Revenues that is subordinate and junior to the lien on the 2025 Series A Subordinate Bonds and any such Parity Swaps on Pledged Revenues.

The Authority will not sell, assign or otherwise dispose of Authority Capacity or any portion thereof except as provided in the Senior Indenture. The Authority will not sell any transmission service utilizing Authority Capacity except as provided in the Transmission Service Contracts or as allowed by applicable tax laws and regulations.

Rate Covenant

The Authority covenants in the 2025 Series A Subordinated Indenture that, as long as any 2025 Series A Subordinate Bonds are Outstanding, it has and will have good right and lawful power to establish charges and cause to be collected amounts with respect to the use of Authority Capacity, subject to the terms of the Transmission Service Contracts.

The Authority covenants in the 2025 Series A Subordinated Indenture that it shall at all times establish charges and cause to be collected amounts for the use of Authority Capacity (including amounts payable under the Transmission Service Contracts) as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment (without duplication) of all amounts required to be paid from Revenues or Available Revenues during such Fiscal Year pursuant to the Senior Indenture, including, but not limited to, all amounts required to be paid from Available Revenues transferred to the Pledged Revenues Accounts during such Fiscal Year pursuant to the Prior Subordinated Indentures, and from the Pledged Revenues during such Fiscal Year pursuant to the 2025 Series A Subordinated Indenture.

The Authority will not furnish or supply or cause to be furnished or supplied any use or service of Authority Capacity free of charge to any person, firm or corporation, public or private, and the Authority will, subject to the 2025 Series A Subordinated Indenture and consistent with the Transmission Project Agreements, enforce the payment of any and all amounts owing to the Authority by reason of Authority Capacity by discontinuing such use or service, or by filing suit therefor, as soon as practicable after any such amounts are due, or by both such discontinuance and by filing suit.

Covenant With Respect to Transmission Service Contracts

Subject to the 2025 Series A Subordinated Indenture, the Authority shall enforce or cause to be enforced the provisions of the Transmission Service Contracts and duly perform its covenants and agreements thereunder. The Authority will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Transmission Service Contracts that will impermissibly reduce the payments required thereunder or which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of Owners under the 2025 Series A Subordinated Indenture; provided that the Authority is not prohibited from amending any Transmission Service Contract to the extent expressly permitted therein. Except as expressly authorized in the Senior Indenture, the Authority will not consent or agree to or permit any rescission or any amendment to or otherwise take any action under or in connection with the Senior Indenture which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Owners under the 2025 Series A Subordinated Indenture.

Annual Budget

The Authority shall adopt and file not less than 30 but no more than 45 days prior to the beginning of each Fiscal Year with the Trustee for each Fiscal Year an Annual Budget prepared in accordance with, and in the manner contemplated by, the Transmission Service Contracts and the Senior Indenture. Each such Annual Budget shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the 2025 Series A Issue Fund, including particularly the amounts required for the accrual or payment (as applicable) of 2025 Series A Accrued Debt Service and the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps, so that the 2025 Series A Payment Account, the 2025 Series A Charges Account, and the 2025 Series A Reserve Account (if funded) shall be maintained at the respective balances required by the 2025 Series A Subordinated Indenture and the provider of any Reserve Account Policy shall be repaid for any draw made under such Reserve Account Policy for the 2025 Series A Reserve Account.

Following the end of each quarter of each Fiscal Year, the Authority shall review its estimates set forth in the Annual Budget for such Fiscal Year, and in the event such estimates do not substantially correspond with the actual revenues, expenses or other requirements, the Authority shall adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year. The Authority may also adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year, if, at any time during such Fiscal Year, extraordinary receipts or payments of unusual costs relating to Authority Capacity, or the amounts in the 2025 Series A Payment Account, the 2025 Series A Reserve Account and the 2025 Series A Charges Account are less than the respective balances required under the 2025 Series A Subordinated Indenture. The Authority may also adopt, at any time in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year.

Accounts and Reports

The Authority shall keep or cause to be kept books of record and account (separate from all other records and accounts) in which complete and correct entries in all material respects shall be made of its transactions relating to the 2025 Series A Issue Fund and each Account established under the 2025 Series A Subordinated Indenture. Such books, together with the Transmission Service Contracts and all other books and papers of the Authority, including insurance policies maintained by the Authority, relating to Authority Capacity, shall at all times be subject to the inspection of the Trustee (who shall have no duty to so inspect) and the Owners of an aggregate of not less than five percent (5%) in principal amount of 2025 Series A Subordinate Bonds then Outstanding or their representatives duly authorized in writing.

The Authority shall cause to be filed annually, within one hundred fifty (150) days after the close of each Fiscal Year, with the Trustee and otherwise as provided by law an annual report for each Fiscal Year, accompanied by an Accountant's Certificate, relating to Authority Capacity and so long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, including the statements required by the Senior Indenture. So long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, such Accountant's Certificate shall state whether or not, to the knowledge of the signer, the Authority is in default with respect to any of the covenants, agreements or conditions on its part contained in the 2025 Series A Subordinated Indenture, and if so, the nature of such default. The Trustee shall not be responsible to review the financial information contained in such annual report.

The Authority shall file with the Trustee (a) forthwith upon becoming aware of any Event of Default or default in the performance by the Authority of any covenant, agreement or condition contained in the 2025 Series A Subordinated Indenture, a certificate of an Authorized Authority Representative specifying such Event of Default or default and (b) within one hundred fifty (150) days after the end of each Fiscal Year, commencing with the first Fiscal Year ending after the issuance of the 2025 Series A Subordinate Bonds, a certificate of an Authorized Authority Representative stating whether, to the best of the signer's knowledge and belief, the Authority has kept, observed, performed and fulfilled its covenants and obligations contained in the 2025 Series A Subordinated Indenture and whether there exists at the date of such certificate any default by the Authority under the 2025 Series A Subordinated Indenture or any Event of Default or other event that would become an Event of Default upon the lapse of time or giving of notice specified in the 2025 Series A Subordinated Indenture and if any such default or Event of Default so exists, the nature and the status thereof.

The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of the 2025 Series A Subordinated Indenture shall be available for inspection by Owners at the office of the Trustee during business hours and with reasonable prior notice and shall be mailed to each Owner who files a written request therefor with the Trustee. The Trustee may charge each Owner requesting such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

Extension of Payment of 2025 Series A Subordinate Bonds

The Authority covenants in the 2025 Series A Subordinated Indenture that it shall not directly or indirectly extend or assent to the extension of the maturity of any of the 2025 Series A Subordinate Bonds or the time of payment of any claims for interest by the purchase or funding of such 2025 Series A Subordinate Bonds or claims for interest or by any other arrangement. If the maturity of any of the 2025 Series A Subordinate Bonds or the time for payment of such claims for interest is extended, such 2025 Series A Subordinate Bonds or claims for interest shall not be entitled, in the case of any default under the

2025 Series A Subordinated Indenture, to the benefit of the 2025 Series A Subordinated Indenture or any payment out of the Pledged Revenues or the 2025 Series A Issue Fund, including the investments, if any, thereof, pledged under the 2025 Series A Subordinated Indenture or the moneys (except moneys held in trust for the payment of particular 2025 Series A Subordinate Bonds or claims for interest pursuant to the 2025 Series A Subordinated Indenture) held by the Fiduciaries, except subject to the prior payment of the principal of all 2025 Series A Subordinate Bonds Outstanding the maturity of which has not been extended and of the portion of accrued interest on the 2025 Series A Subordinate Bonds which is not represented by such extended claims for interest. Nothing in the 2025 Series A Subordinated Indenture shall be deemed to limit the right of the Authority to issue refunding bonds or other evidence of indebtedness to refund the 2025 Series A Subordinate Bonds and such issuance shall not be deemed to constitute an extension of maturity of the 2025 Series A Subordinate Bonds.

Application of Available Revenues; Priority of Payment

The Authority shall set aside or cause to be set aside in the General Reserve Fund under the Senior Indenture in each month Available Revenues in amounts at least sufficient to meet (1) the requirements for such month determined pursuant to the 2025 Series A Subordinated Indenture and (2) all other payments or transfers of Available Revenues required to be made in such month, including all payments or transfers of Available Revenues required to be made in such month pursuant to the Prior Subordinated Indentures. Moneys set aside or transferred to meet the requirements of the Prior Subordinated Indentures shall be applied in a manner such that none shall have priority over or otherwise rank prior to the others. On or before the last Business Day of each month the Authority shall apply or cause to be applied Available Revenues by transfer thereof from said General Reserve Fund (consistent with the 2025 Series A Subordinated Indenture), to the 2025 Series A Pledged Revenues Account in the amount required to meet the requirements for such month determined pursuant to the 2025 Series A Subordinated Indenture.

The Authority shall not authorize or permit any Available Revenues to be set aside, transferred or applied for any purpose pursuant to such terms and provisions or in any manner such that the setting aside, transfer or application shall have priority over or otherwise rank prior to the requirements described above for the setting aside, transferring and application of Available Revenues to meet the requirements determined pursuant to the 2025 Series A Subordinated Indenture.

Amendments and Supplemental Indentures

Except as otherwise provided in the 2025 Series A Subordinated Indenture, any modification or amendment of the 2025 Series A Subordinated Indenture and of the rights and obligations of the Authority and of the Owners of the 2025 Series A Subordinate Bonds may be made by the Authority by a Supplemental Indenture with the written consent of the Owners of at least a majority in aggregate principal amount of 2025 Series A Subordinate Bonds then Outstanding and, if less than all of the Outstanding 2025 Series A Subordinate Bonds are affected by the amendment, the Owners of at least a majority in aggregate principal amount of Outstanding 2025 Series A Subordinate Bonds so affected. Moreover, if such amendment or modification will not take effect so long as any 2025 Series A Subordinate Bonds of any specified like maturity remain Outstanding, the consent of the Owners of such 2025 Series A Subordinate Bonds will not be required, and such 2025 Series A Subordinate Bonds shall not be deemed to be Outstanding for the purposes of such calculation. No such amendment or modification shall permit a change in the terms of redemption or maturity of the principal of any Outstanding 2025 Series A Subordinate Bonds or of any installment of interest thereon or make any reduction in the principal amount, Redemption Price (if applicable), or interest rate thereon without the consent of the Owner of such 2025 Series A Subordinate Bond, or reduce the percentages of the consents of the Owners of which are required to effect any such amendment or modification, or change or modify any of the rights or obligations of any Fiduciary without its written assent thereto.

The Authority may adopt Supplemental Indentures of Trust without the consent of the Owners for any of the following purposes: (1) to add to the covenants and agreements of the Authority contained in the 2025 Series A Subordinated Indenture, other covenants and agreements to be observed by the Authority that are not contrary to or inconsistent with the 2025 Series A Subordinated Indenture then in effect; (2) to add to the limitations and restrictions contained in the 2025 Series A Subordinated Indenture, other limitations and restrictions to be observed by the Authority that are not contrary to or inconsistent with the 2025 Series A Subordinated Indenture then in effect; (3) to confirm, as further assurance, any security interest or pledge created under the 2025 Series A Subordinated Indenture; (4) to modify, amend or supplement the 2025 Series A Subordinated Indenture in such manner as to permit the qualification thereof under the Trust Indenture Act of 1939, as amended, or any similar federal statute hereafter in effect, and to add such other terms, conditions and provisions as may be permitted by said act or similar federal statute, and which shall not materially and adversely affect the interests of the Owners of any of the 2025 Series A Subordinate Bonds; (5) to modify any of the provisions of the 2025 Series A Subordinated Indenture in any other respect if (i) no 2025 Series A Subordinate Bonds are Outstanding at the date of execution of such Supplemental Indenture of Trust or (ii) (a) such modification shall be, and be expressed to be, effective only after all 2025 Series A Subordinate Bonds then Outstanding at the date of the execution and delivery of such Supplemental Indenture of Trust shall cease to be Outstanding and (b) such Supplemental Indenture of Trust shall be specifically referred to in the text of all 2025 Series A Subordinate Bonds authenticated and delivered after the date of execution and delivery of such Supplemental Indenture of Trust and of 2025 Series A Subordinate Bonds issued in exchange therefor or in place thereof; (6) to amend, modify, or supplement the 2025 Series A Subordinated Indenture in such manner as does not materially adversely affect the rights of the Owners of the 2025 Series A Subordinate Bonds (including, but not limited to, amending, modifying or supplementing the 2025 Series A Subordinated Indenture in such manner as the Authority deems appropriate to provide for an interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement payable on a basis subordinate and junior to the 2025 Series A Subordinate Bonds and any Parity Swaps, as provided in the 2025 Series A Subordinated Indenture), provided that the Trustee is first furnished with an Opinion of Bond Counsel to the effect that such amendment, modification or supplement is permitted under the 2025 Series A Subordinated Indenture and shall not adversely affect the validity of the 2025 Series A Subordinate Bonds or the exclusion of interest on the 2025 Series A Subordinate Bonds from gross income of the Owners for federal income tax purposes; and (7) to comply with additional requirements that a Rating Agency may impose in order to issue or maintain a rating on the 2025 Series A Subordinate Bonds, provided that any Supplemental Indenture the purpose of which is to effect such changes shall be effective only upon delivery to the Authority and the Trustee of an Opinion of Bond Counsel that such changes shall not adversely affect the validity of the 2025 Series A Subordinate Bonds or the exclusion of interest on the 2025 Series A Subordinate Bonds from the gross income of the Owners thereof for federal income tax purposes.

The Authority may adopt Supplemental Indentures of Trust with the consent of the Trustee (without the consent of any Owners of the 2025 Series A Subordinate Bonds) to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in the 2025 Series A Subordinated Indenture or to insert such provisions clarifying matters or questions arising under the 2025 Series A Subordinated Indenture as are necessary or desirable and not contrary to or inconsistent with the 2025 Series A Subordinated Indenture.

Fiduciaries

The Trustee may at any time resign by giving not less than 60 days' written notice to the Authority and any Parity Swap Providers specifying the date when such resignation shall take effect, and such resignation shall take effect upon the day specified in such notice unless previously a successor shall have been appointed by the Authority with the approval of the Owners as provided in the 2025 Series A Subordinated Indenture and such successor shall have accepted such appointment, in which event such resignation shall take effect immediately on the appointment of such successor. The Trustee may at any time be removed by (i) an instrument in writing, filed with the Trustee, signed by two Authorized Authority Representatives, unless an Event of Default has occurred and is continuing, or (ii) an instrument or concurrent instruments in writing, filed with the Trustee, and signed by the Owners of a majority in principal amount of the 2025 Series A Subordinate Bonds then Outstanding or their attorneys-in-fact duly authorized. Such removal shall take effect immediately upon the appointment of a successor as provided in the 2025 Series A Subordinated Indenture and acceptance of such appointment by such successor.

In case at any time the Trustee resigns or is removed or has become incapable of acting, or is adjudged as bankrupt or insolvent, or if a receiver, liquidator or conservator of the Trustee or of its property is appointed, or if any public officer takes charge or control of the Trustee or of its property or affairs, a successor Trustee may be appointed by the Owners of a majority in principal amount of 2025 Series A Subordinate Bonds then Outstanding as described in the 2025 Series A Subordinated Indenture, and failing such an appointment the Authority shall appoint a successor to hold office until a successor Trustee shall be appointed by the Owners. The Trustee and each successor Trustee, if any, shall be a bank, a trust company, or a national banking association, doing business and having a corporate trust office in either New York, New York, Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $100,000,000, if there be such a bank, trust company or national banking association willing and able to accept the appointment on reasonable and customary terms and authorized by law to perform all the duties imposed on it by the 2025 Series A Subordinated Indenture.

The 2025 Series A Subordinated Indenture provides for the appointment by the Authority of a Paying Agent (which may include the Trustee). The Trustee, the Paying Agent or either or both of them, as may be appropriate, are a Fiduciary for purposes of the 2025 Series A Subordinated Indenture.

If no Event of Default is occurring, the Trustee shall perform only such duties as are specifically set forth in the 2025 Series A Subordinated Indenture. If an Event of Default has occurred and has not been cured or waived, the Trustee shall exercise such of the rights and powers vested in it by the 2025 Series A Subordinated Indenture, and use the same degree of care and skill in its exercise as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. Subject to the above, no Fiduciary shall be liable in connection with the performance of its duties under the 2025 Series A Subordinated Indenture except for its own negligence, misconduct or default.

The Authority is required to cause to be paid each Fiduciary reasonable compensation for all services rendered under the 2025 Series A Subordinated Indenture and all reasonable expenses, charges, counsel fees and other disbursements incurred in the performance of its powers and duties under the 2025 Series A Subordinated Indenture. Each Fiduciary has a lien on any and all funds held by it under the 2025 Series A Subordinated Indenture securing its right to compensation. The Authority also agrees to indemnify and save each Fiduciary, its officers, directors, employees and agents harmless, to the extent permitted by law, against any claims, costs, expenses or liabilities that it may incur in the exercise and performance of its powers and duties under the 2025 Series A Subordinated Indenture that are not due to its negligence, misconduct or default.

Defeasance

If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to Owners of all 2025 Series A Subordinate Bonds the principal or Redemption Price (if applicable) of and interest due or to become due thereon, and to the Parity Swap Providers (if any) all of the amounts owed by the Authority under any Parity Swaps, at the times and in the manner stipulated therein and in the 2025 Series A Subordinated Indenture, then the lien of the 2025 Series A Subordinated Indenture and all covenants, agreements and other obligations of the Authority to the Owners and any such Parity Swap Providers, shall thereupon cease, terminate and become void and be discharged and satisfied, provided however that notwithstanding anything to the contrary in the 2025 Series A Subordinated Indenture, upon the defeasance of the 2025 Series A Subordinate Bonds, the Authority's and the Trustee's obligations with respect to execution, registration of transfer and exchange of 2025 Series A Subordinate Bonds under the 2025 Series A Subordinated Indenture shall not be discharged until such 2025 Series A Subordinate Bonds, and all accrued and unpaid interest, have been paid in full at the maturity thereof. In such event, the Trustee shall cause an accounting for such period or periods as shall be requested by the Authority to be prepared and filed with the Authority and, upon the request of the Authority shall execute and deliver to the Authority all such instruments as may be desirable to evidence such discharge and satisfaction, and the Fiduciaries shall pay over or deliver, as directed by the Authority, all moneys or securities held by them pursuant to the 2025 Series A Subordinated Indenture that are not required for the payment of principal or Redemption Price (if applicable) and interest due or to become due on the 2025 Series A Subordinate Bonds not theretofore surrendered for such payment or redemption.

The 2025 Series A Subordinate Bonds (which may be less than all of the 2025 Series A Subordinate Bonds then Outstanding) or interest installments for the payment or redemption of which moneys shall have been set aside and shall be held in trust by the Paying Agents (through deposit pursuant to the 2025 Series A Subordinated Indenture of funds for such payment or redemption or otherwise) at the maturity, payment or redemption date thereof shall be deemed to have been paid within the meaning and with the effect expressed in the above paragraph. Any Outstanding 2025 Series A Subordinate Bonds shall prior to the maturity or redemption date thereof be deemed to have been paid within the meaning and with the effect expressed in the above paragraph if (a) in case any of said 2025 Series A Subordinate Bonds are to be redeemed (if applicable) on any date prior to their maturity, the Authority shall have given to the Trustee irrevocable instructions accepted in writing by the Trustee, as provided in the 2025 Series A Subordinated Indenture, to mail a notice of redemption of such 2025 Series A Subordinate Bonds on said date, (b) there shall have been deposited with the Trustee either moneys in an amount that shall be sufficient, or Defeasance Obligations (including any Defeasance Obligations issued or held in book-entry form on the books of the Department of the Treasury of the United States) the principal of and the interest on which when due will provide moneys that, together with the moneys, if any, on deposit with the Trustee, shall be sufficient, in the opinion of an independent certified public accountant or independent arbitrage consultant, to pay when due the principal or Redemption Price (if applicable) and interest due and to become due on said 2025 Series A Subordinate Bonds on and prior to the redemption date or maturity date thereof, as the case may be, and (c) in the event such 2025 Series A Subordinate Bonds are not by their terms subject to redemption within the next succeeding sixty (60) days, the Authority shall have given a trustee, which may be the Trustee, in form satisfactory to such trustee, irrevocable instructions to mail, as soon as practicable, a notice to the registered Owners of such 2025 Series A Subordinate Bonds a notice that the deposit required by (b) above has been made with such trustee and that said 2025 Series A Subordinate Bonds are deemed to have been paid in accordance with the 2025 Series A Subordinated Indenture and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal or Redemption Price (if applicable) on such 2025 Series A Subordinate Bonds. Neither Defeasance Obligations nor moneys deposited with the Trustee pursuant to the 2025 Series A Subordinated Indenture nor principal or interest payments on any such Defeasance Obligations shall be withdrawn or used for any purpose other than, and shall be held in trust for, the payment of the principal or Redemption Price (if applicable) and interest on said 2025 Series A Subordinate Bonds; provided that any cash received from such principal or interest payments on such Defeasance Obligations deposited with the Trustee, (A) to the extent such cash will not be required at any time for such purpose, as determined by an independent certified public accountant or independent arbitrage consultant, shall be paid over upon the direction of the Authority as received by the Trustee, free and clear of any trust, lien, pledge or assignment securing said 2025 Series A Subordinate Bonds or otherwise existing under the 2025 Series A Subordinated Indenture, and (B) to the extent such cash will be required for such purpose at a later date, shall, to the extent practicable, be reinvested pursuant to the direction of the Authority in Defeasance Obligations (including any Defeasance Obligations issued or held in book-entry form on the books of the Department of the Treasury of the United States) maturing at times and in amounts sufficient to pay when due the principal or Redemption Price (if applicable) and interest to become due on said 2025 Series A Subordinate Bonds, on or prior to such redemption date or maturity date thereof, as the case may be, and interest earned from such reinvestments shall be paid over as received by the Trustee, free and clear of any lien, pledge or security interest securing said 2025 Series A Subordinate Bonds or otherwise existing under the 2025 Series A Subordinated Indenture.

Any request, consent, revocation of consent or other instrument that the 2025 Series A Subordinated Indenture may require or permit to be signed and executed by the Bondowners may be in one or more instruments of similar tenor, and shall be signed or executed by such Bondowners in person or by their attorneys or representatives, appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney or representative, or (ii) the holding by any person of the 2025 Series A Subordinate Bonds shall be sufficient for any purpose of the 2025 Series A Subordinated Indenture (except as otherwise therein expressly provided) if made in accordance with the 2025 Series A Subordinated Indenture, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable.

Events of Default and Remedies

Each of the following constitute an Event of Default under the 2025 Series A Subordinated Indenture: (1) except as otherwise provided in the 2025 Series A Subordinated Indenture, the failure to pay the principal or Redemption Price (if applicable) of any 2025 Series A Subordinate Bond when and as the same shall become due and payable, whether at maturity or by call for redemption or otherwise; (2) default in the due and punctual payment of any installment of interest on any 2025 Series A Subordinate Bond, when and as such interest installment shall become due and payable; (3) default by the Authority in the performance or observance of any other of the covenants, agreements or conditions on its part in the 2025 Series A Subordinated Indenture or in the 2025 Series A Subordinate Bonds contained, and such default shall continue for a period of one hundred twenty (120) days after written notice thereof to the Authority by the Trustee or to the Authority and to the Trustee by the Owners of not less than ten percent (10%) in principal amount of the 2025 Series A Subordinated Bonds Outstanding; and (4) the occurrence of an Event of Default (as defined in the Senior Indenture) under the Senior Indenture.

Upon the occurrence of any Event of Default which has not been remedied, the Authority shall, if demanded in writing by the Trustee, account, as if it were the trustee of an express trust, for all Pledged Revenues and other moneys, securities and funds pledged or held under the 2025 Series A Subordinated Indenture for such period as stated in the demand. During the continuance of an Event of Default, the Trustee shall apply all moneys, securities, funds and Pledged Revenues pledged to the benefit of the Owners of the 2025 Series A Subordinate Bonds and any Parity Swap Providers (a) received by the Trustee pursuant to any right given or action taken under the 2025 Series A Subordinated Indenture and (b) held by the Trustee pursuant and subject to the terms and conditions of the 2025 Series A Subordinated Indenture in the following order: *first*, to the payment of the reasonable fees and expenses of the Trustee for performance of its duties under the 2025 Series A Subordinated Indenture (including those of its counsel) and including those incurred during any period of default; *second*, to the payment to the persons entitled thereto of all installments of interest on the 2025 Series A Subordinate Bonds then due in the order in which such installments became due, together with accrued and unpaid interest on the 2025 Series A Subordinate Bonds theretofore called for redemption (if applicable), and, if the amount available shall not be sufficient to pay in full any installment or installments due on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and *third*, to the payment to the persons entitled thereto of the unpaid principal or Redemption Price (if applicable) of any 2025 Series A Subordinate Bonds that shall have become due, whether at maturity or by call for redemption, and all obligations under any Parity Swaps that shall have become due and payable (with any termination payments due under any Parity Swaps being payable on a basis subordinate and junior to the payment of the principal or Redemption Price (if applicable) of any 2025 Series A Subordinate Bonds), in the order of their due dates, and, if the amount available shall not be sufficient to pay in full all the 2025 Series A Subordinate Bonds and any Parity Swaps (other than termination payments thereunder) due on any date, then to the payment thereof ratably, according to the amounts of principal or Redemption Price or payments due under any Parity Swaps (other than termination payments thereunder) due on such date, to the persons entitled thereto, without any discrimination or preference.

If an Event of Default has occurred and has not been remedied, the Trustee may, and upon written request of the Owners of not less than a majority in aggregate principal amount of the 2025 Series A Subordinate Bonds Outstanding, to the extent indemnified as provided in the 2025 Series A Subordinated Indenture, shall, proceed to protect and enforce its rights and the rights of the Owners under the 2025 Series A Subordinated Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the 2025 Series A Subordinated Indenture, or in aid of the execution of any power granted in the 2025 Series A Subordinated Indenture or any remedy granted under the Act, or for an accounting against the Authority as if it were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee, being advised by counsel, deems most effectual to enforce any of its rights or to perform any of its duties under the 2025 Series A Subordinated Indenture. Regardless of the happening of an Event of Default, the Trustee shall have the power to, but unless requested in writing by the Owners of a majority in principal amount of the 2025 Series A Subordinate Bonds then Outstanding and furnished with reasonable security and indemnity shall be under no obligation to, institute and maintain such suits and proceedings as it may be advised shall be necessary or expedient to prevent any impairment of the security under the 2025 Series A Subordinated Indenture or as it may be advised shall be necessary or expedient to preserve or protect the interests of the Trustee and of the Owners of the 2025 Series A Subordinate Bonds.

No Owner shall have any right to institute any suit, action or proceeding at law or in equity for the enforcement of any provision of the 2025 Series A Subordinated Indenture or the execution of any trust under the 2025 Series A Subordinated Indenture or for any remedy under the 2025 Series A Subordinated Indenture, unless (1) such Owner previously has given the Trustee written notice of the happening of an Event of Default as provided in the 2025 Series A Subordinated Indenture, (2) the Owners of at least a majority in aggregate principal amount of the 2025 Series A Subordinate Bonds then Outstanding have filed a written request with the Trustee and have offered the Trustee reasonable opportunity to exercise its powers or to institute such suit, action or proceeding in its own name, (3) there have been offered to the Trustee by such Owners adequate security and indemnity against its costs, expenses and liabilities to be incurred, and (4) the Trustee has refused to comply with such request for a period of sixty (60) days after receipt by it of such notice, request and offer of indemnity.

Notice of Default

The Trustee shall promptly mail notice of the occurrence of any Event of Default to each Owner of the 2025 Series A Subordinate Bonds then Outstanding at his or her address, if any, appearing upon the registry books of the Trustee.

Unclaimed Moneys

Any moneys held by a Fiduciary in trust for the payment and discharge of any of the principal of, Redemption Price (if applicable) of or interest on any of the 2025 Series A Subordinate Bonds which remain unclaimed for one year after the date when the payment shall have become due and payable, shall be repaid by the Fiduciary to the Authority, as its absolute property and free from trust, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Owners not yet paid shall look only to the Authority for the payment of such 2025 Series A Subordinate Bonds.

SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS

The following is a summary of certain provisions of the Transmission Service Contracts entered into between Southern California Public Power Authority (in this summary, "SCPPA") and each of the Transmission Service Purchasers, which consist of the Department of Water and Power of The City of Los Angeles and the cities of Anaheim, Riverside, Pasadena, Burbank and Glendale. Except as described in this summary, all of the Transmission Service Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Transmission Service Contracts and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Transmission Service Contracts.

The Agreement

SCPPA and each of the Transmission Service Purchasers have entered into a Transmission Service Contract (the "Transmission Service Contract") pursuant to which the Transmission Service Purchasers will contract with SCPPA for transmission service utilizing SCPPA Capacity so as to provide for transmission of capacity and energy from the Intermountain Power Project and other resources.

SCPPA intends to issue Bonds and Notes sufficient to finance or refinance the costs of acquiring SCPPA Capacity. The payments required to be made under the Transmission Service Contracts are to be pledged by SCPPA as security for the payment of such Bonds, and the interest thereon, subject to the application thereof to such purposes and on such terms as provided in the Senior Indenture.

Definitions

Agreements for the Acquisition of Capacity: The several Agreements for the Acquisition of Capacity between SCPPA and the Transmission Service Purchasers, as the same may be amended and supplemented from time to time in accordance with their terms.

Annual Budget: The budget adopted by the Board of Directors pursuant to the Transmission Service Contracts not less than 30 nor more than 45 days prior to the beginning of each Transmission Service Year, including any amendments thereto, which shall show a detailed estimate of the items for such Transmission Service Year upon which Monthly Transmission Costs for such Transmission Service

Year are computed and all revenues, income or other funds to be applied to such costs, for and applicable to such Transmission Service Year.

Available Transmission Capability: At any point in time, the operating capability of the Transmission Project as determined in accordance with the IPP Power Sales Contracts.

Billing Statement: The written statement prepared (or caused to be prepared) each Month by SCPPA which shall be based upon the Annual Budget and which shall show for such Month the amount to be paid to the Trustee by the Transmission Service Purchasers in accordance with the provisions of the Transmission Service Contracts.

Bond Resolution: The resolution entitled "Power Supply Revenue Bond Resolution," adopted by IPA on September 28, 1978, as heretofore amended and supplemented and as hereafter from time to time amended and supplemented in conformity with its provisions and the provisions of the IPP Power Sales Contracts.

Cost of Acquisition of Capacity: All costs and expenses of acquiring and financing or refinancing SCPPA Capacity. Such costs shall include all payments under the Southern Transmission System Agreement which are applied or are to be applied thereunder to the payment of the Cost of Acquisition and Construction, costs incurred by SCPPA in connection with the financing or refinancing of SCPPA Capacity and SCPPA Expenses. There shall be applied, as a credit against the Cost of Acquisition of Capacity, interest earned on investments, all if and to the extent held or paid into the SCPPA Construction Fund. Subject to the foregoing, Cost of Acquisition of Capacity shall include, but shall not be limited to, funds required for the following:

(1) The Cost of Acquisition and Construction, and any other amounts paid or to be paid to IPA pursuant to the Southern Transmission System Agreement;

(2) SCPPA Expenses;

(3) Financial and legal costs and expenses and such amount of reserves as are required by the Senior Indenture;

(4) Subject to the requirements of the Act, interest accruing in whole or in part on Bonds prior to and during construction of the Transmission Project and for such additional period, consistent with the Act, as SCPPA may reasonably determine to be necessary in accordance with the provisions of the Senior Indenture;

(5) Amounts, if any, required by the Senior Indenture to be paid from the proceeds of Bonds issued to finance the Cost of Acquisition of Capacity into the Debt Service Reserve Account in the Debt Service Fund or the Reserve and Contingency Fund or into any other funds or accounts established pursuant to the Senior Indenture;

(6) The payment of principal, premium, if any, and interest due (whether at the maturity of principal or at the due date of interest or upon redemption) of any Note;

(7) To the extent not included in Cost of Acquisition and Construction, all costs of insurance applicable to the period of construction of the Transmission Project;

(8) To the extent not included in Cost of Acquisition and Construction, all costs relating to injury and damage claims arising out of the construction of the Transmission Project, less proceeds of insurance; and

(9) All other costs properly allocable to the acquisition and financing or refinancing of SCPPA Capacity.

Date of Firm Operation: With respect to the Initial Facilities, the initial date recommended by the Project Manager and determined by the Coordinating Committee on which the Initial Facilities can reasonably be expected to operate reliably.

FERC Accounts: The Federal Energy Regulatory Commission Uniform Systems of Accounts prescribed for Class A and Class B Public Utilities and licensees, as the same may be modified, supplemented or amended from time to time.

Initial Facilities: The Southern Transmission System as described in the Transmission Service Contracts. Such description shall be amended from time to time to conform to the description of the Southern Transmission System in the IPP Power Sales Contracts.

Monthly Transmission Costs: All of SCPPA's costs, to the extent attributable to SCPPA Capacity and to the extent not paid from the proceeds of Bonds or Notes, resulting from the acquisition and financing or refinancing of SCPPA Capacity. There shall be applied, as a credit against Monthly Transmission Costs, any interest earned on investments if and to the extent not credited against the Cost of Acquisition of Capacity. Monthly Transmission Costs shall include, but not be limited to, the items of cost and expense referred to in the Transmission Service Contracts that are attributable to SCPPA Capacity and are accrued or paid during each Month of each Transmission Service Year. In the event any Transmission Service Year shall cover fewer than 12 Months, the fraction expressed in subparagraphs (4), (5) and (6) below shall be adjusted accordingly, and, in the event of any revision of the Annual Budget after the commencement of any Transmission Service Year, the amount determined pursuant to subparagraphs (4), (5) and (6) below shall be appropriately adjusted so that any increase or decrease in the portion of the Annual Budget applicable to said subparagraphs shall be evenly apportioned over the remaining Months of such Transmission Service Year. Monthly Transmission Costs shall include without duplication:

(1) The Monthly Power Costs allocable to the Transmission Project, pursuant to the IPP Power Sales Contracts.

(2) The amount which is required under the Senior Indenture to be paid or deposited during such month into any funds or accounts established by the Senior Indenture for Debt Service and for any reserve requirements for Bonds.

(3) The amount which is required to be paid or deposited during such Month into any fund or account established by the Senior Indenture or otherwise for the payment of interest (net of any interest subsidy with respect to Bonds paid to or for the account of SCPPA by any governmental body or agency) on Notes.

(4) One-twelfth of the amount (not otherwise included under any item described under this definition of Monthly Transmission Costs) which is required under the Senior Indenture to be paid or deposited during such Transmission Service Year into any other fund established by the Senior Indenture, and shall include, without limitation, amounts required to

make up a deficiency in any such fund whether or not resulting from a default in payments by any Transmission Service Purchaser of amounts due under any Transmission Service Contract.

(5) One-twelfth of the amount necessary during such Transmission Service Year to pay costs of providing transmission service during such Transmission Service Year (including SCPPA Expenses) to the extent not included in subparagraph (1) hereof.

(6) One-twelfth of the amount necessary during such Transmission Service Year to pay or provide reserves for all taxes required to be paid by SCPPA with respect to SCPPA Capacity to the extent not included in subparagraph (1) hereof.

SCPPA Capacity: The right of SCPPA to capacity in the Transmission Project, pursuant to the Agreements for the Acquisition of Capacity.

SCPPA Expenses: The costs, expenses and fees incurred by SCPPA in carrying out its duties, responsibilities and obligations, and exercising its rights, under the Act and the Transmission Project Agreements.

Southern Transmission System Agreement: The Southern Transmission System Agreement between SCPPA and IPA, as the same may be hereafter amended or supplemented.

Transmission Project: The Initial Facilities and any Capital Improvements.

Transmission Project Agreements: The Senior Indenture, the Transmission Service Contracts, the Southern Transmission System Agreement, the Agreements for the Acquisition of Capacity, the IPP Power Sales Contracts, the Bond Resolution of IPA and any other contract designated a Transmission Project Agreement by the Board of Directors.

Transmission Service Share: The percentage of the total transmission service utilizing SCPPA Capacity to which a particular Transmission Service Purchaser is entitled in accordance with the terms of its Transmission Service Contract.

Transmission Service Shares

SCPPA will provide transmission service utilizing SCPPA Capacity to the Transmission Service Purchasers in accordance with the following:

(1) All transmission service utilizing SCPPA Capacity shall be scheduled in accordance with the practices and procedures established pursuant to the Transmission Project Agreements. At all times after the Date of Firm Operation each Transmission Service Purchaser shall be entitled to schedule transmission service utilizing SCPPA Capacity up to the amount obtained by multiplying its Transmission Service Share by the Available Transmission Capability.

(2) Operation of the Transmission Project shall be subject to scheduled outages or curtailments and restrictions imposed by any regulatory authority and Uncontrollable Forces.

(3) It is the obligation of each Transmission Service Purchaser, at its own expense, to secure access to the main AC bus adjacent to each converter terminal of the Transmission Project, which are the terminal points for the Transmission Project. Such access may be by physical connection or by contract path. In no event shall SCPPA have any obligation to provide

transmission or wheeling services from such terminal points to the electric system of the Transmission Service Purchaser.

Pledge of Payments

All payments required to be made by the Transmission Service Purchasers in accordance with or pursuant to any provision of the Transmission Service Contracts, are pledged by SCPPA to secure the payment of the Bonds, the interest thereon, and the interest on the Notes subject to the application thereof to such purposes and on such terms as provided in the Senior Indenture securing such Bonds. SCPPA, in the Transmission Service Contracts, assigns the payments referenced in the Transmission Service Contracts to the Trustee and directs each Transmission Service Purchaser to pay such amounts directly to the Trustee.

Nature of Obligation

Each Transmission Service Purchaser is obligated to make payments required under its Transmission Service Contract solely from its electric revenue funds as a cost of transmission service and an operating expense of its electric utility system. Each such Transmission Service Purchaser has covenanted to include in its annual electric system budget for each fiscal year during the term of its Transmission Service Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such Transmission Service Contract. The obligations, which are several and not joint, to make payments of Monthly Transmission Costs under the respective Transmission Service Contracts are not subject to reduction or offset if the Transmission Project or any part thereof is not completed, is not operating or operable or if its service is suspended, interfered with, reduced, curtailed or terminated in whole or in part. In addition, the Transmission Service Purchasers' obligations under the Transmission Service Contracts are not subject to any reduction or offset and are not conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

Term

The Transmission Service Contracts shall constitute a binding obligation of the parties thereto from and after the effective date, and the term of such Transmission Service Contracts shall end on June 15, 2027 or such later date upon which all Bonds and Notes and the interest thereon shall have been paid in full or adequate provisions for such payment shall have been made, unless terminated sooner in accordance with the provisions for termination or amendment described below.

Required Payments

For a discussion on Monthly Transmission Costs and the payment obligations of the respective Transmission Service Purchasers with respect thereto, see "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS – Transmission Service Contracts" in the front part of this Official Statement.

Rate Covenants of Transmission Service Purchasers

Each Transmission Service Purchaser has covenanted in its Transmission Service Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay all amounts payable when due under its Transmission Service Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

Board of Directors

SCPPA is administered by a Board of Directors comprised of the chief executive officer (or his or her designee) of the electric utility of each member of SCPPA. The Transmission Service Purchasers are entitled to participate in Transmission Project Matters in accordance with voting rights given to them as a member of SCPPA. See "SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY - Organization and Management" in the front part of this Official Statement. SCPPA, through its Board of Directors, has the following duties and responsibilities, among others: (1) provide liaison among the Transmission Service Purchasers; (2) attempt to resolve any disputes among SCPPA, the Transmission Service Purchasers, the Agent, the Project Manager or the Operating Agent relating to the Transmission Project; (3) review, modify and approve (i) the practices and procedures to be followed by the Transmission Service Purchasers relating to the scheduling and controlling of capacity and energy from the Transmission Project, (ii) all Capital Improvements, the budgets therefor and the provisions for financing thereof and (iii) all amendments and supplements to the Transmission Project insurance program; (4) approve all consultants or advisors on financial and legal matters that may be retained by SCPPA; (5) approve the issuance of each series of Bonds and evidences of indebtedness issued in anticipation of the issuance of Bonds; and (6) perform other functions provided for in the Transmission Service Contracts and the other Transmission Project Agreements.

Restrictions on Disposition

A Transmission Service Purchaser may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that: (1) the Transmission Service Purchaser assigns its interest under its Transmission Service Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Transmission Service Purchaser under the Transmission Service Contract; (2) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency; (3) an independent engineer selected by SCPPA delivers an opinion that such purchaser or lessee is reasonably able to charge and collect rates and charges required to meet its obligations under the Transmission Service Contract; (4) it is determined by the Board of Directors that the disposition will not adversely affect the value of such Transmission Service Contract as security for the Bonds; and (5) Bond Counsel has rendered an opinion that such disposition will not adversely affect the exemption from federal income taxation of interest payable on the Bonds (if applicable).

Defaults and Remedies

The failure of a Transmission Service Purchaser to perform any of its obligations, including the obligation to make required payments, under its Transmission Service Contract will constitute a default. In the event of a default or inability to perform by a Transmission Service Purchaser under its Transmission Service Contract, SCPPA may proceed to enforce the Transmission Service Purchaser's covenants or obligations thereunder, or may seek damages or injunctive relief for the breach thereof, by action at law or equity, or if a payment due under the Transmission Service Contract remains unpaid when due, SCPPA may, upon 90 days' written notice to the Transmission Service Purchaser, discontinue the delivery of capacity and energy to such Transmission Service Purchaser. The discontinuance of transmission service to a defaulting Transmission Service Purchaser by SCPPA will not reduce the obligation of such Transmission Service Purchaser to make payments under its Transmission Service Contract. In the event the delivery of capacity and energy to a Transmission Service Purchaser in default is discontinued, SCPPA shall transfer to all other Transmission Service Purchasers which are not in default and which so request, a pro rata portion of the defaulting Transmission Service Purchaser's rights to delivery of capacity and energy. In the case of such a transfer, the Transmission Service Purchasers accepting additional rights to delivery of capacity and energy and use of Transmission Project facilities shall assume the defaulting Transmission Service Purchaser's obligations with respect to the rights which are transferred to them. In the event less than all of a defaulting Transmission Service Purchaser's rights to delivery of capacity and energy is transferred to nondefaulting Transmission Service Purchasers, SCPPA shall, to the extent possible, dispose of such remaining rights on the best terms readily available, and in such a manner as, in the opinion of Bond Counsel, does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Bonds (if applicable). The obligation of the defaulting Transmission Service Purchaser to SCPPA shall be reduced to the extent that SCPPA receives payments with respect to the rights of such Transmission Service Purchaser which are transferred. For a further discussion of remedies, see "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS - Transmission Service Contracts" in the front part of this Official Statement.

Termination or Amendment

As long as any Bonds issued under the Senior Indenture or any Notes issued under a Note Resolution are outstanding or until provision has been made for the payment of any Bonds and Notes outstanding in accordance with the Senior Indenture, the Transmission Service Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the Bonds or the Notes or which will impair or adversely affect the rights of the holders of the Bonds or the Notes. Each Transmission Service Contract also provides that SCPPA may not, without the written consent of each of the Transmission Service Purchasers, amend or supplement the Senior Indenture (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Transmission Service Purchasers under the Transmission Service Contracts or to the disadvantage of the Transmission Service Purchasers or to result in increased Monthly Transmission Costs to the Transmission Service Purchasers.

Contracts Subject to Senior Indenture

It has been recognized by the Transmission Service Purchasers in the Transmission Service Contracts that SCPPA, in acquiring, financing or refinancing of SCPPA Capacity, must comply with the requirements of the Senior Indenture, the other Transmission Project Agreements and all licenses, permits and regulatory approvals necessary therefor. The Transmission Service Purchasers have therefore agreed that the Transmission Service Contracts are subject to the provisions of the Senior Indenture, the other Transmission Project Agreements and such licenses, permits and approvals.

SUMMARY OF CERTAIN PROVISIONS OF THE IPP POWER SALES CONTRACTS

The following is a summary of certain provisions of the IPP Power Sales Contracts, as amended (including the amendments effected by the Amendatory Power Sales Contracts), entered into between IPA and each of the IPP Purchasers. Except as described in this summary, all of the IPP Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such IPP Power Sales Contracts and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in the Official Statement have the meanings set forth in the IPP Power Sales Contracts.

Entitlement to Capacity

Each IPP Purchaser is entitled to receive under its IPP Power Sales Contract capacity and energy from the Generation Station up to its Generation Entitlement Share, as specified in its IPP Power Sales Contract, of the available capacity of the Generation Station. An IPP Purchaser may arrange to dispose of capacity or energy from IPP to which it is entitled, but any such arrangements will not affect its obligations under its IPP Power Sales Contract. Each IPP Purchaser's entitlement to the use of the operating capabilities of the Southern and Northern Transmission Systems shall be determined by dividing the portion of such IPP Purchaser's Generation Entitlement Share to be delivered at Points of Delivery on the Southern Transmission System, in the case of the Southern Transmission System, and at Points of Delivery on the Northern Transmission System, in the case of the Northern Transmission System, by the aggregate of those portions of all IPP Purchasers' Generation Entitlement Shares to be delivered at the Points of Delivery on the Southern Transmission System and the Northern Transmission System, respectively. IPP Purchasers having unused entitlements to transmission capacity may agree to allow other IPP Purchasers to use such entitlement except that no IPP Purchaser may use the transmission system in excess of its respective entitlement share if such use would adversely affect the eligibility for federal income tax exemption of the interest payable on the bonds issued by IPA.

Nature of Obligation

Each IPP Purchaser which is a municipally owned electric system is obligated to make the payments required under its IPP Power Sales Contract solely from the revenues of its electric system as a cost of purchased electric capacity and energy and an operating expense. Each such IPP Purchaser has covenanted to include in its annual power system budget for each fiscal year during the term of its IPP Power Sales Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such IPP Power Sales Contract. The IPP Power Sales Contracts constitute a general obligation of each IPP Purchaser which is not a municipally owned electric system. The IPP Purchasers' obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective IPP Power Sales Contracts are not subject to reduction or offset if IPP is not completed, operating or operable or if its output (and as a result, the capacity available to each of the IPP Purchasers) is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the IPP Purchasers' payment obligations under the IPP Power Sales Contracts are not conditioned upon the performance by IPA or any other party (including any other IPP Purchaser) of contractual or other obligations and are not subject to any reduction or offset in the event of any default by IPA in the performance of its obligations under the IPP Power Sales Contracts.

Term

The term of each IPP Power Sales Contract has commenced and will end on June 15, 2027, unless terminated sooner in accordance with the provisions for termination or amendment described below.

Rate Covenants of Municipal Purchasers

Each IPP Purchaser which is a municipally owned electric system has covenanted in its IPP Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay to IPA all amounts payable under its IPP Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

IPP Coordinating Committee

The IPP Power Sales Contracts provide for the establishment of an IPP Coordinating Committee composed of representatives of the IPP Purchasers and IPA which is to (a) provide liaison among IPA and the IPP Purchasers, (b) make recommendations to the Project Manager and Operating Agent with respect to the construction and operation of the Project, (c) review, modify and approve the practices and procedures formulated by the Project Manager and Operating Agent under the Construction Management and Operating Agreement, including procedures for the scheduling and controlling of capacity and energy from IPP and procedures with respect to operation of generating units and fuel storage, the schedule of planned maintenance outages, all budgets and revisions thereof prepared and submitted by the Project Manager or Operating Agent pursuant to the Construction Management and Operating Agreement, all Capital Improvements and the budgets therefor and provisions for financing thereof, the insurance program with respect to IPP and revisions to the description of IPP contained in the IPP Power Sales Contracts, (d) approve all consultants or advisors on financial matters, including bond counsel, that may be retained by IPA, (e) make recommendations to IPA concerning the issuance of bonds and evidences of indebtedness issued in anticipation of the issuance of bonds and (f) perform other functions provided for in the IPP Power Sales Contracts and the Construction Management and Operating Agreement. No action by the IPP Coordinating Committee pursuant to its authority under the IPP Power Sales Contracts or otherwise shall require IPA to act in a manner inconsistent with, or refrain from acting as required by, the Bond Resolution of IPA or any applicable licenses, permits or regulatory provisions.

Any action taken by the IPP Coordinating Committee shall require an affirmative decision of representatives of IPP Purchasers having Voting Rights aggregating at least 80%. If the IPP Coordinating Committee is unable to, or fails to, agree and act with respect to the review, modification or approval of certain actions of the Project Manager or Operating Agent after a reasonable opportunity to do so or within the time limits specified in the Construction Management and Operating Agreement, the Project Manager or Operating Agent may take such actions subject to the terms of the Construction Management and Operating Agreement. The term Voting Rights means at any particular time with respect to an IPP Purchaser, such Purchaser's Generation Entitlement Share in effect at such time under its IPP Power Sales Contract.

Restrictions on Disposition

An IPP Purchaser may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that (i) the IPP Purchaser assigns its interest under its IPP Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the IPP Purchaser under the IPP Power Sales Contract, (ii) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency and (iii) it is determined by IPA that the disposition will not adversely affect the value of such IPP Power Sales Contract as security for the bonds or affect the eligibility for tax exempt status of bonds issued by IPA. In addition, an IPP Purchaser may not sell, assign or otherwise dispose of any portion of its Generation Entitlement Share or the capacity rights granted under its Purchaser's IPP Power Sales Contract in the Northern Transmission System or the

Southern Transmission System except if it is determined by IPA that the disposition will not adversely affect the eligibility for exemption from federal income taxes of interest on the bonds issued by IPA.

Defaults and Remedies

The failure of an IPP Purchaser to perform any of its obligations, including the obligation to make required payments under its IPP Power Sales Contract, will constitute a default. In the event of a default or inability to perform by an IPP Purchaser under its IPP Power Sales Contract, IPA may proceed to enforce the IPP Purchaser's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity, or if a payment due under the IPP Power Sales Contract remains unpaid when due, IPA may, upon 120 days' written notice to the IPP Purchaser, discontinue the delivery of capacity and energy to, and the use of IPP facilities by, such IPP Purchaser while the default continues. Except as a result of a transfer of the defaulting IPP Purchaser's rights to delivery of capacity and energy and the use of IPP facilities described below, the discontinuance of delivery of capacity and energy to, and the use of IPP facilities by, a defaulting IPP Purchaser by IPA will not reduce the obligation of such IPP Purchaser to make payments under its IPP Power Sales Contract.

In the event the delivery of capacity and energy to, and use of IPP facilities by, an IPP Purchaser in default is discontinued, IPA shall transfer to all other IPP Purchasers which are not in default and which so request, a pro rata portion of a defaulting IPP Purchaser's rights to delivery of capacity and energy and use of IPP facilities. In the case of such a transfer, the IPP Purchasers accepting additional rights to delivery of capacity and energy and use of IPP facilities shall assume the defaulting IPP Purchaser's obligations with respect to the rights which are transferred to them, other than the obligation to cure any deficiency in payment which may have occurred prior to such transfer. In the event less than all of a defaulting IPP Purchaser's rights to delivery of capacity and energy and use of IPP facilities is transferred to non-defaulting IPP Purchasers, IPA shall, to the extent possible, dispose of such remaining rights on the best terms readily available in accordance with procedures formulated by the IPP Coordinating Committee, and in such a manner as does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the bonds issued by IPA. The obligation of the defaulting IPP Purchaser to IPA shall be reduced to the extent that IPA receives payments with respect to the rights of such IPP Purchaser which are transferred.

Termination or Amendment

As long as any bonds issued under the Bond Resolution of IPA are outstanding or until provision has been made for the payment of any bonds outstanding in accordance with the Bond Resolution of IPA, the IPP Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the bonds issued by IPA or which will impair or adversely affect the rights of the holders of such bonds. Each IPP Power Sales Contract also provides that IPA may not, without the consent of each of the IPP Purchasers, amend or supplement the IPA Bond Resolution (except to provide for the issuance of additional bonds or Subordinated Indebtedness), to affect the rights and obligations of the IPP Purchasers under the IPP Power Sales Contracts or to be to the disadvantage of the IPP Purchasers or to result in increased Monthly Power Costs to the IPP Purchasers.

Contracts Subject to Bond Resolution

It has been recognized by the IPP Purchasers in the IPP Power Sales Contracts that IPA, in financing, acquiring, constructing and operating the Project, must comply with the requirements of the IPA Bond Resolution and all licenses, permits and regulatory approvals necessary therefor, and the IPP

Purchasers have therefore agreed that the IPP Power Sales Contracts are subject to the provisions of the IPA Bond Resolution and such licenses, permits and approvals.

Payments-In-Aid of Construction

If requested by IPA, one or more IPP Purchasers or an agency acting on its or their behalf may agree to make payments-in-aid of construction for the Generation Station. The California Purchasers and the Utah Purchasers or any entity acting on their respective behalf may agree to make payments-in-aid of construction for the Southern Transmission System and the Northern Transmission System, respectively. All payments-in-aid of construction will be deposited in the account in the Construction Fund relating to the facility with respect to which such payments are being made and, subject to the lien and pledge of and covenants under the IPA Bond Resolution with respect to such Fund, all such deposits will be used by IPA for the payment of the Cost of Acquisition and Construction with respect to such facility. The payments-in-aid of construction will not change or otherwise affect IPA's ownership of such facility or of IPP or any of the rights and obligations of IPA or the IPP Purchasers under the IPP Power Sales Contracts.

Use and Disposition of Certain Facilities

In recognition of the fact that IPP consists of certain rights, properties and facilities that could be used in connection with the construction and operation at the IPP site of additional generating units or transmission facilities, IPA may, with the approval of the IPP Coordinating Committee, sell, lease or otherwise make available such rights, properties and facilities for such construction or operation of other units or facilities at the IPP site. All amounts received shall be credited against Cost of Acquisition and Construction or Monthly Power Costs, as appropriate. No such disposition may interfere with the construction and operation of IPP or adversely affect the eligibility for federal income tax exemption of the interest payable on the bonds issued by IPA.

Expansion of Southern Transmission System

Any proposal for a major expansion of the Southern Transmission System is to be initiated by the IPP Coordinating Committee. Such proposal must comply with the Project Agreements and must provide that, subject to compliance with Utah law, the IPP Purchasers having entitlements to the Southern Transmission System under their respective IPP Power Sales Contracts will have the right to participate in the additional capacity of such expansion in proportion to their respective entitlements shares. Upon approval of any such proposal by IPA and the IPP Coordinating Committee, IPA will use its best efforts to proceed with the development of such expansion.

Certain Interconnection Agreements

The IPP Purchasers agree that IPA may comply with the requirements of the Mona Interconnection Agreement or other agreements approved by the IPP Coordinating Committee with respect to furnishing start up and black start power from IPP. All amounts received by IPA for furnishing such service shall be credited against Monthly Power Costs.

Transmission Service

Subject to contractual rights with respect to the Northern Transmission System, IPA may schedule the unused capacity of such System for transmission service for other utilities. All amounts received by IPA for furnishing such service shall be credited against Monthly Power Costs.

Insurance Provisions

IPA will take reasonable and prudent steps to maintain properly designed and properly underwritten IPP property and casualty insurance programs during the construction phase of IPP and will design and arrange underwriting for property and casualty insurance programs for the operating phase of IPP. IPA will make every economically feasible effort to incorporate into the operation phase of IPP property insurance program extra-expense and business interruption coverage tied to all perils covered by the property insurance program and covering losses resulting from failure or interruption of the fuel supply for IPP.

SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENTS FOR THE ACQUISITION OF CAPACITY

The following is a summary of certain provisions of the Agreements for the Acquisition of Capacity (the "Acquisition Agreements"). This summary is not to be considered a full statement of the terms of the Acquisition Agreements and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Acquisition Agreements.

Assignment of Capacity

Each Transmission Project Participant (consisting of the Department of Water and Power of The City of Los Angeles and the California cities of Anaheim, Riverside, Pasadena, Burbank and Glendale) and Southern California Public Power Authority (in this summary, "SCPPA") have entered into an Acquisition Agreement pursuant to which each Transmission Project Participant has assigned its right to capacity in the Transmission Project to SCPPA and SCPPA has agreed to issue bonds, notes, or other evidences of indebtedness and to make payments-in-aid of construction of the Transmission Project to the Intermountain Power Agency ("IPA").

Pursuant to the Acquisition Agreements, the Transmission Project Participants have assigned, transferred, conveyed, set over and relinquished to SCPPA in accordance with the Acquisition Agreements all of the Transmission Project Participants' rights and interests in the Southern Transmission System in accordance with the IPP Power Sales Contracts. Such rights and interests consist of the Transmission Project Participants' rights to capacity of the Southern Transmission System and all of the Transmission Project Participants' contract rights under the IPP Power Sales Contracts relating to the Southern Transmission System.

Nature of Obligation

SCPPA in the Acquisition Agreements agrees to issue bonds, notes or other evidences of indebtedness to provide funds to make payments-in-aid of construction with respect to the Southern Transmission System on behalf of the Transmission Project Participants pursuant to the terms of the Southern Transmission Agreement.

The Transmission Project Participants in the Acquisition Agreements agree that all payments of Monthly Power Costs with respect to the Southern Transmission System to be made by the Transmission Project Participants, which shall be made by SCPPA to IPA pursuant to the Southern Transmission System Agreement and received by IPA, shall be applied in discharge of the Transmission Project Participants' obligation to make such payments of Monthly Power Costs under the IPP Power Sales Contracts, and the Transmission Project Participants' obligation to pay such Monthly Power Costs shall be discharged only to the extent of such receipt. The obligation of the Transmission Project Participants to pay Monthly Power Costs under the IPP Power Sales Contracts shall continue and shall not otherwise be affected by the Southern Transmission System Agreement or by the Acquisition Agreements, except as discharged as provided in the Acquisition Agreements.

Assignment of Transmission Project Participants' Interests

SCPPA and the Transmission Project Participants recognize that the Transmission Project Participants in accordance with the IPP Power Sales Contract have entered into or may enter into agreements with other entities pursuant to which such entities shall have rights, including the right to use capacity in the Southern Transmission System available to the Transmission Project Participants which may be in excess of the needs of the Transmission Project Participants which exist from time to time. The assignment under the Acquisition Agreements of the Transmission Project Participants' rights and interests shall not affect the rights of any such entity or entities as aforesaid. It is further recognized that such rights of said entities may, if exercised or otherwise effectuated, result in rights of such entities with respect to the Transmission Project Participants' Transmission Service Share. SCPPA shall, on behalf of the Transmission Project Participants, provide portions of the Transmission Project Participants' Transmission Service Share to the entities on such terms as shall be agreed upon by the Transmission Project Participants consistent with the rights of such entities; provided, however, that no such arrangement shall release the Transmission Project Participants from any obligation under the Acquisition Agreements or under the Transmission Service Contracts.

The Acquisition Agreements became effective upon the first issuance by SCPPA of bonds, notes or other evidences of indebtedness to finance the acquisition of capacity rights in the Southern Transmission System.

Amendment or Termination

The Acquisition Agreements shall terminate concurrently with the termination of the Transmission Service Contracts between SCPPA and the Transmission Project Participants. Upon such termination, the rights and interests of SCPPA derived under the Acquisition Agreements shall cease and terminate and such rights and interests shall revert to the Transmission Project Participants.

The Transmission Project Participants agree that they will not consent to any amendment to the IPP Power Sales Contracts without the prior written consent of SCPPA.

SUMMARY OF CERTAIN PROVISIONS OF THE SOUTHERN TRANSMISSION SYSTEM AGREEMENT

The following is a summary of certain provisions of the Southern Transmission System Agreement, dated as of May 1, 1983, between Intermountain Power Agency ("IPA") and Southern California Public Power Authority (in this summary, "SCPPA"), as amended by the First Amendment to Southern Transmission System Agreement, dated as of November 1, 2008 (as so amended, the "STS Agreement"). This summary is not to be considered a full statement of the terms of the STS Agreement and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the STS Agreement.

Definitions

Agreements for the Acquisition of Capacity: The several Agreements for the Acquisition of Capacity between SCPPA and the Transmission Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms.

Billing Statement: The written statement prepared or caused to be prepared each Month by IPA which shall be based upon the Annual Budget and which shall show for such Month the amount to be paid to IPA by each Transmission Project Participant and shall indicate the Monthly Power Costs allocated to the Transmission Project pursuant to the IPP Power Sales Contracts.

Bond Resolution: The resolution entitled "Power Supply Revenue Bond Resolution," adopted by IPA on September 28, 1978, as heretofore amended and supplemented, including as amended and supplemented by the resolution entitled "Amended and Restated Power Supply Revenue Bond Resolution," adopted by IPA on August 28, 1998, and as hereafter from time to time amended and supplemented in conformity with its provisions and the provisions of the IPP Power Sales Contracts.

Construction Management and Operating Agreement: The Construction Management and Operating Agreement entered into between IPA and the Department of Water and Power of The City of Los Angeles relating to the construction and operation of IPP as from time to time amended and supplemented in conformity with the provisions of the IPP Power Sales Contracts.

SCPPA First Bonding Date: The date upon which SCPPA first issued and delivered bonds pursuant to the SCPPA Indenture of Trust to finance its payments-in-aid of construction for the Southern Transmission Initial Facilities, and, as applicable to the STS Upgrade Project, (i) the date upon which SCPPA first issued and delivered bonds, notes or other evidences of indebtedness to finance its payments-in-aid of construction for the STS Upgrade Project or (ii) the date upon which SCPPA first deposited in the SCPPA Transmission Project Construction Fund an amount from its available funds to provide for its payments-in-aid of construction for the STS Upgrade Project, whichever date shall be earlier.

Southern Transmission Capital Improvements: Capital Improvements (as defined in the IPP Power Sales Contracts) to the extent related to the Southern Transmission Initial Facilities and expressly including the STS Upgrade Project.

Southern Transmission Cost of Acquisition and Construction: All costs and expenses of planning, designing, acquiring, constructing, installing and financing the Transmission Project, placing the Transmission Project in operation, disposal of the Transmission Project, and obtaining governmental approvals, certificates, permits and licenses with respect thereto paid or incurred by IPA (all as further defined in the IPP Power Sales Contracts).

Southern Transmission Initial Facilities: The Southern Transmission System which consists of DC transmission and conversion facilities necessary to deliver capacity and energy from the Intermountain Power Project Generation Station to the point of delivery at Adelanto. Such facilities shall terminate at appropriate switchracks and shall include rights-of-way, a microwave communication system, and all other buildings, structures, facilities and appurtenances which shall be necessary or incidental in the useful construction and operation of such facilities.

STS Upgrade Project: The additions and improvements to and renewals of the Southern Transmission System that provided for an increase of the capacity of the Transmission Project from 1920 MW to 2400 MW.

Transmission Project: The Southern Transmission Initial Facilities and any Southern Transmission Capital Improvements.

Transmission Project Participant: Each of the following entities, together with their respective successors and assigns: Department of Water and Power of The City of Los Angeles; City of Anaheim; City of Riverside; City of Pasadena; City of Burbank; and City of Glendale.

Transmission Service Contracts: The several Transmission Service Contracts, dated as of May 1, 1983, between SCPPA and the Transmission Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms and the terms of SCPPA's Indenture of Trust.

The STS Agreement

SCPPA and IPA have entered into the STS Agreement pursuant to which SCPPA is able to issue bonds, notes or other evidences of indebtedness to provide funds to fulfill its obligation to make payments-in-aid of construction with respect to the Transmission Project by making payments to IPA in accordance with the terms of the STS Agreement.

Reports

IPA will prepare and issue to SCPPA copies of all information and reports relating to the Transmission Project required to be provided to the Transmission Project Participants in accordance with the IPP Power Sales Contracts, which shall include the following reports:

(1) Financial and operating statements relating to the Transmission Project.

(2) Status of Annual Budget.

(3) Status of construction budget for the Transmission Project during construction.

(4) Analysis of operations relating to the Transmission Project.

Performance of IPA Obligations by Others

Pursuant to the Construction Management and Operating Agreement, certain of the obligations and covenants of IPA under the IPP Power Sales Contracts and the IPA Bond Resolution will be performed and complied with, on behalf of IPA, by the Project Manager and Operating Agent under the Construction Management and Operating Agreement. In addition, IPA has entered into the Personnel Service Contract, effective as of June 2, 1982, with Intermountain Power Service Corporation, pursuant to which certain of the obligations and covenants of IPA under the IPP Power Sales Contracts and the IPA Bond Resolution will be performed and complied with, on behalf of IPA, by said Corporation under said Contract.

Financing Plans

SCPPA will advise IPA in writing on the first business day of each Month of SCPPA's periodic financing plans and the amount of funds then on deposit in the SCPPA Transmission Project Construction Fund to provide for payments-in-aid of construction to be applied to Southern Transmission Cost of Acquisition and Construction.

On or after the SCPPA First Bonding Date, IPA will not issue any bonds, notes or other evidences of indebtedness to finance, and will not use the proceeds of any bonds, notes or other evidences of indebtedness to pay, Southern Transmission Cost of Acquisition and Construction, except (a) as provided in the STS Agreement, or (b) as otherwise required to avoid any breach or default by IPA under the IPP Power Sales Contracts or the IPA Bond Resolution. Notwithstanding any issuance or use of proceeds by IPA pursuant to clause (b) above, the rights and obligations of SCPPA to undertake financings and make payments-in-aid of construction pursuant to the STS Agreement shall continue (including such rights and obligations as they pertain to that portion of the Southern Transmission Cost of Acquisition and Construction for which such issuance or use of proceeds by IPA was undertaken or made); and IPA shall bill SCPPA, and SCPPA shall make payments-in-aid of construction, with respect to any such portion of the Southern Transmission Cost of Acquisition and Construction in a manner similar to that provided in the STS Agreement with payment for such billing to be made by SCPPA within fifteen days after receipt or such longer period until SCPPA shall have funds available for such payment.

In the event SCPPA shall fail to consummate any financing contemplated by the STS Agreement within the period permitted therein, IPA may, upon prior written notice by IPA to SCPPA, issue its bonds, notes or other evidences of indebtedness to finance, and may use the proceeds of bonds, notes or other evidences of indebtedness to pay, Southern Transmission Cost of Acquisition and Construction.

Upon the giving by IPA of notice in accordance with the STS Agreement, the rights and obligations of SCPPA to undertake financings and make payments-in-aid of construction pursuant to the STS Agreement shall terminate; provided, however, that the then remaining funds in the SCPPA Transmission Project Construction Fund available for such purpose shall continue to be paid to IPA in accordance with the provisions of the STS Agreement.

Budgets; Billings; Payments-in-Aid of Construction

IPA will provide, or cause to be provided, to SCPPA: (i) at the time each revised budget required by the Construction Management and Operating Agreement is approved, a copy of such revised budget as so approved (together with a new computation of STS Direct Costs and STS Allocated Costs based on such revised budget and the then current cost allocation under the STS Agreement); (ii) at the time any revision to any such budget is approved as aforesaid, a copy of such revision (including such a computation); and (iii) with respect to the STS Upgrade Project, (a) at the time each revised operating budget that includes provisions for the STS Upgrade Project (the "STS Upgrade Project Budget") that has been submitted and approved as required by the Construction Management and Operating Agreement and the IPP Power Sales Contracts is approved, a copy of such revised budget as so approved (together with a computation of STS Direct Costs and STS Allocated Costs based on such STS Upgrade Project Budget and the applicable then current cost allocation under the STS Agreement) and (b) at the time any revision to any STS Upgrade Project Budget is approved.

SCPPA shall be entitled to rely upon each revised budget, requisition or billing provided to it. Any such reliance by SCPPA shall not be deemed a waiver by SCPPA of any rights it may have as a result of a subsequent audit of the costs included therein.

IPA and SCPPA recognize and agree that all payments-in-aid of construction by SCPPA shall be paid from, and only from, funds on deposit and available in the SCPPA Transmission Project Construction Fund and only upon compliance with the requirements of the SCPPA Indenture of Trust regarding the withdrawal and expenditure of funds. Payments-in-aid of construction by SCPPA for the STS Upgrade Project shall be made from funds deposited in the SCPPA Transmission Project

Construction Fund from the proceeds of bonds, notes or other evidences of indebtedness issued by SCPPA or from other funds available to it.

All such payments shall be deposited in the appropriate account or accounts under the IPA Bond Resolution. Each such deposit shall be and become part of such account or accounts and IPA will, subject to the lien and pledge of and covenants under the IPA Bond Resolution with respect to such account or accounts, use such deposits only for payment of the Southern Transmission Cost of Acquisition and Construction. Pending application of any such deposit to Southern Transmission Cost of Acquisition and Construction, IPA shall invest all or any portion thereof in accordance with the IPA Bond Resolution.

Neither such payments-in-aid of construction by SCPPA nor the STS Agreement shall change or otherwise affect IPA's ownership of the Transmission Project or any of the rights and obligations of IPA or the Transmission Project Participants under the IPP Power Sales Contracts, except to the extent that the obligation of IPA to issue its bonds for the payment of the Southern Transmission Cost of Acquisition and Construction is impacted thereby.

IPA, in the STS Agreement, recognizes that, under the IPP Power Sales Contracts, to the extent that payments-in-aid of construction by SCPPA are received and applied to the payment of the Southern Transmission Cost of Acquisition and Construction, IPA will not be obligated to issue bonds for the payment of such Cost and consequently, to that extent, Monthly Power Costs allocated to the Transmission Project pursuant to the IPP Power Sales Contracts will be reduced, reflecting the application of such payments to Southern Transmission Cost of Acquisition and Construction in lieu of the issuance of bonds of IPA therefor and the allocation of debt service on such bonds to the Transmission Project.

Assignment of the Participants' Rights Under the IPP Power Sales Contracts

Pursuant to the STS Agreement, IPA consents to the assignment to SCPPA by each Transmission Project Participant of rights under its IPP Power Sales Contract, including its right to the capacity in the Transmission Project, in accordance with the Agreements for the Acquisition of Capacity. SCPPA agrees that it will not sell, assign or otherwise dispose of the rights to capacity in the Transmission Project acquired by it pursuant to the Agreements for the Acquisition of Capacity unless such sale, assignment or disposition (a) is as provided in the Transmission Service Contracts, or (b) is preceded by a resolution of IPA determining (which determination shall not be unreasonably withheld) that such sale, assignment or other disposition will not adversely affect the eligibility for exemption from federal income taxes of the interest paid, or to be paid, on the bonds of IPA with respect to IPP.

IPP Power Sales Contracts Obligations

For each month after the SCPPA First Bonding Date, SCPPA will make the payments to IPA required to be made by the Transmission Project Participants pursuant to the IPP Power Sales Contracts for the Monthly Power Costs allocable to the Transmission Project; provided, that, SCPPA shall make such payments only to the extent that funds are available therefor in the Operating Fund established under the Senior Indenture. Each payment made by SCPPA pursuant to the STS Agreement shall be accompanied by a schedule setting forth the portion thereof being made on behalf of each Transmission Project Participant. For each month after the SCPPA First Bonding Date, for the purpose of determining the payments to be made by SCPPA on behalf of the Transmission Project Participants, IPA in the STS Agreement agrees to provide to SCPPA (concurrent with providing said Billing Statements to the Transmission Project Participants) a copy of the Billing Statement, if any, sent to each Transmission Project Participant pursuant to the IPP Power Sales Contracts.

IPA agrees in the STS Agreement that all payments of Monthly Power Costs made by SCPPA pursuant to the STS Agreement and received by IPA shall be accepted and applied in discharge of the respective Transmission Project Participants' obligations to pay such Monthly Power Costs under the IPP Power Sales Contracts and the Transmission Project Participants' obligations to pay such Monthly Power Costs shall be discharged to the extent of the receipt of such payments by IPA. Such payments shall not otherwise affect the rights and obligations of IPA or the Transmission Project Participants under the IPP Power Sales Contracts.

APPENDIX D

FORM OF CONTINUING DISCLOSURE UNDERTAKING FOR THE 2025 SERIES A SUBORDINATE BONDS

Continuing Disclosure Undertaking
for the purpose of providing
continuing disclosure information
under Section (b)(5) of Rule 15c2-12

____, 2025

This Continuing Disclosure Undertaking (the "Agreement") is executed and delivered by the Southern California Public Power Authority (the "Authority") in connection with the issuance of its $________ Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "Bonds"). The Bonds are being issued pursuant to the Indenture of Trust, dated as of [_________] 1, 2025 (the "2025 Series A Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee").

In consideration of the issuance of the Bonds by the Authority and the purchase of such Bonds by the beneficial owners thereof, the Authority covenants and agrees as follows:

1. Purpose of This Agreement. This Agreement is executed and delivered by the Authority as of the date set forth below, for the benefit of the beneficial owners of the Bonds and in order to assist the Participating Underwriter in complying with the requirements of the Rule (as defined below). The Authority represents that it will be the only "obligated person" within the meaning of the Rule with respect to the Bonds at the time the Bonds are delivered to the Participating Underwriter and that no other person is expected to become so committed at any time after the issuance of the Bonds.

2. Definitions. (a) The terms set forth below shall have the following meanings in this Agreement, unless the context clearly otherwise requires.

"Annual Financial Information" means the financial information and operating data described in Exhibit I.

"Annual Financial Information Disclosure" means the dissemination of disclosure concerning Annual Financial Information and the dissemination of the Audited Financial Statements as set forth in Section 4.

"Audited Financial Statements" means collectively, the audited financial statements of the Authority and each Obligated Project Participant (relating to its electric utility fund), each prepared pursuant to the standards and as described in Exhibit I.

"Business Day" means any day other than (a) a Saturday or Sunday, or (b) a day on which commercial banks in New York, New York or the cities in which are located the designated corporate trust offices of the Dissemination Agent or the designated operational office of the Authority are authorized by law or executive order to close.

"Dissemination Agent" means any agent designated as such in writing by the Authority and which has filed with the Authority a written acceptance of such designation, and such agent's successors and assigns.

"EMMA" means the MSRB through its Electronic Municipal Market Access system for municipal securities disclosure or through any other electronic format or system prescribed by the MSRB for purposes of the Rule.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Final Official Statement" means the Official Statement dated _____, 2025, relating to the Bonds.

"Financial Obligation" means (a) a debt obligation, (b) a 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) a guarantee of an obligation or instrument described in clause (a) or (b) of this definition; provided however, the term Financial Obligation does not include municipal securities as to which a final official statement has been provided to the MSRB consistent with the Rule.

"MSRB" means the Municipal Securities Rulemaking Board.

"Obligated Project Participant" means the Department of Water and Power of The City of Los Angeles, the City of Anaheim and the City of Riverside.

"Participating Underwriter" means each broker, dealer or municipal securities dealer acting as an underwriter in the primary offering of the Bonds.

"Reportable Event" means the occurrence of any of the Events with respect to the Bonds set forth in Exhibit II.

"Reportable Events Disclosure" means dissemination of a notice of a Reportable Event as set forth in Section 5.

"Rule" means Rule 15c2-12 adopted by the SEC under the Exchange Act, as the same may be amended from time to time.

"SEC" means the Securities and Exchange Commission.

"Undertaking" means the obligations of the Authority pursuant to Sections 4 and 5.

(b) Capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Indenture.

3. <u>CUSIP Numbers</u>. The CUSIP Numbers of the Bonds are as follows:

MATURITY	AMOUNT	CUSIP NUMBER
	$	

The Authority will include the CUSIP Numbers (or applicable CUSIP Number) in all disclosure described in Sections 4 and 5 of this Agreement.

4. Annual Financial Information Disclosure. Subject to Section 9 of this Agreement, the Authority hereby covenants that it will disseminate or cause to be disseminated on its behalf its Annual Financial Information and the Audited Financial Statements (in the form and by the dates set forth in Exhibit I) to EMMA in such manner and format and accompanied by identifying information as is prescribed by the MSRB or the SEC at the time of delivery of such information and by such time so that such entities receive the information by the dates specified.

If any part of the Annual Financial Information can no longer be generated because the operations to which it is related have been materially changed or discontinued, the Authority will disseminate a statement to such effect as part of the Annual Financial Information for the year in which such event first occurs.

If any amendment or waiver is made to this Agreement, the Annual Financial Information for the year in which such amendment is made (or in any notice or supplement provided to EMMA) shall contain a narrative description of the reasons for such amendment and its impact on the type of information being provided.

5. Reportable Events Disclosure. Subject to Section 8 of this Agreement, the Authority hereby covenants that it will disseminate in a timely manner (not in excess of ten business days after the occurrence of the Reportable Event) Reportable Events Disclosure to EMMA in such manner and format and accompanied by identifying information as is prescribed by the MSRB or the SEC at the time of delivery of such information. References to "material" in Exhibit II refer to materiality as it is interpreted under the Exchange Act. Notwithstanding the foregoing, notice of optional or unscheduled redemption of any Bonds or defeasance of any Bonds need not be given under this Agreement any earlier than the notice (if any) of such redemption or defeasance is given to the Bondholders pursuant to the Indenture.

6. Consequences of Failure of the Authority to Provide Information. The Authority shall give notice in a timely manner to EMMA of any failure to provide Annual Financial Information Disclosure when the same is due hereunder.

In the event of a failure of the Authority to comply with any provision of this Agreement, the beneficial owner of any Bond may seek mandamus or specific performance by court order, to cause the Authority to comply with its obligations under this Agreement. The beneficial owners of 25% or more in principal amount of the Bonds outstanding may challenge the adequacy of the information provided under this Agreement and seek specific performance by court order to cause the Authority to provide the information as required by this Agreement. A default under this Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Agreement in the event of any failure of the Authority to comply with this Agreement shall be an action to compel performance.

7. Amendments; Waiver. Notwithstanding any other provision of this Agreement, the Authority by resolution authorizing such amendment or waiver, may amend this Agreement, and any provision of this Agreement may be waived, if:

(a) (i) The amendment or waiver is made in connection with a change in circumstances that arises from a change in legal requirements, including without limitation pursuant to a "no-action" letter issued by the SEC, change in law, or change in the identity, nature, or status of the Authority, or type of business conducted; or

(ii) This Agreement, as amended, or the provision, as waived, would have complied with the requirements of the Rule at the time of the primary offering, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(b) The amendment or waiver does not materially impair the interests of the beneficial owners of the Bonds, as determined either by parties unaffiliated with the Authority (such as the Trustee), or by approving vote of Bondholders pursuant to the terms of the Indenture at the time of the amendment.

If the SEC, the MSRB or other regulatory authority approve or require Annual Financial Information Disclosure or Reportable Events Disclosure to be made to a central post office, governmental agency or similar entity other than EMMA or in lieu of EMMA, the Authority shall, if required, make such dissemination to such central post office, governmental agency or similar entity without the necessity of amending this Agreement.

8. Termination of Undertaking. The Undertaking of the Authority shall be terminated hereunder if the Authority no longer has any legal liability for any obligation on or relating to repayment of the Bonds under the Indenture. The Authority shall give notice to EMMA in a timely manner if this Section is applicable.

9. Dissemination Agent. The Authority may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Agreement, and may discharge any such Dissemination Agent with or without appointing a successor Dissemination Agent.

10. Additional Information. Nothing in this Agreement shall be deemed to prevent the Authority from disseminating any other information, using the means of dissemination set forth in this Agreement or any other means of communication, or including any other information in any Annual Financial Information Disclosure or notice of occurrence of a Reportable Event, in addition to that which is required by this Agreement. If the Authority chooses to include any information from any document or notice of occurrence of a Reportable Event in addition to that which is specifically required by this Agreement, the Authority shall have no obligation under this Agreement to update such information or include it in any future disclosure or notice of occurrence of a Reportable Event. If the name of the Authority is changed, the Authority shall disseminate such information to EMMA.

11. Beneficiaries. This Agreement has been executed in order to assist the Participating Underwriter in complying with the Rule; however, this Agreement shall inure solely to the benefit of the Authority, the Dissemination Agent, if any, and the beneficial owners of the Bonds, and shall create no rights in any other person or entity.

12. Recordkeeping. The Authority shall maintain records of all Annual Financial Information Disclosure and Reportable Events Disclosure, including the content of such disclosure, the names of the entities with whom such disclosure was filed and the date of filing such disclosure.

13. Assignment. The Authority shall not transfer its obligations under the Indenture unless the transferee agrees to assume all obligations of the Authority under this Agreement or to execute an Undertaking under the Rule.

14. Governing Law. This Agreement shall be governed by the laws of the State of California.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By ____

Daniel E. Garcia
Executive Director

EXHIBIT I

ANNUAL FINANCIAL INFORMATION AND TIMING AND AUDITED FINANCIAL STATEMENTS

"Annual Financial Information" means financial information and operating data, including:

(a) 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 Project as set forth under the section entitled "THE SOUTHERN TRANSMISSION PROJECT" and under the subsection entitled "INTERMOUNTAIN POWER PROJECT - Operating Statistics" in Appendix B; and

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

(b) 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.

(c) Updated versions of the type of information for the Anaheim Public Utilities electric system (the "Anaheim Electric System") 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 the Anaheim Electric System; and

2. the summary of financial results of the Anaheim Electric System.

(d) Updated versions of the type of information for the Riverside Public Utilities electric system (the "Riverside Electric System") 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 the Riverside Electric System; and

2. the summary of financial results of the Riverside Electric System.

(e) such other information and data as the Authority may deem necessary in order to comply with the requirements of the Rule.

"Audited Financial Statements" means the audited financial statements of the Authority and each Obligated Project Participant's electric utility fund, in each case for the most recent fiscal year (commencing with the fiscal year ended June 30, 2025), in each case prepared in accordance with generally accepted accounting principles as promulgated to comply with governmental entities from time to time (or such other accounting principles as may be applicable to the Authority and the Project Participant, as the case may be, in the future pursuant to applicable law).

All or a portion of the Annual Financial Information and the Audited Financial Statements set forth above may be included by reference to other documents which have been submitted to EMMA or filed with the SEC. If the information included by reference is contained in a final official statement, the final official statement must be available on EMMA. The final official statement need not be available from the SEC. The Authority shall clearly identify each such item of information included by reference.

Annual Financial Information with respect to each Obligated Project Participant shall be submitted to EMMA by each December 31 after the end of such Obligated Project Participant's fiscal year, commencing with the fiscal year ending June 30, 2025.

Annual Financial Information with respect to the Authority (i.e., the information described in clauses (b) and (c) of the definition of Annual Financial Information) will be submitted to EMMA by each December 31 after the end of the Authority's fiscal year, commencing with the fiscal year ending June 30, 2025.

Audited Financial Statements as described above should be filed at the same times as the Annual Financial Information for each Obligated Project Participant and the Authority. If Audited Financial Statements are not available when such Annual Financial Information is filed, unaudited financial statements shall be included.

If any change is made to the Annual Financial Information as permitted by Section 4 of the Agreement, the Authority will disseminate a notice of such change as required by Section 4.

EXHIBIT II

EVENTS WITH RESPECT TO THE BONDS
FOR WHICH REPORTABLE EVENTS DISCLOSURE IS REQUIRED

1. Principal and interest payment delinquencies

2. Non-payment related defaults, if material

3. Unscheduled draws on debt service reserves reflecting financial difficulties

4. Unscheduled draws on credit enhancements reflecting financial difficulties

5. Substitution of credit or liquidity providers, or their failure to perform

6. Adverse tax opinions, 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 security, or other material events affecting the tax status of the security

7. Modifications to the rights of security holders, if material

8. Bond calls, if material, and tender offers

9. Defeasances

10. Release, substitution or sale of property securing repayment of the securities, if material

11. Rating changes

12. Bankruptcy, insolvency, receivership or similar event of the Authority*

13. The consummation of a merger, consolidation, or acquisition involving the Authority or the sale of all or substantially all of the assets of the Authority, 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

14. Appointment of a successor or additional trustee or the change of name of a trustee, if material

15. Incurrence of a Financial Obligation of the Authority or any Obligated Project Participant (relating to its electric utility fund), if material, or agreement to covenants, events of default,

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* This event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for the obligated person in a proceeding under the U.S. 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 the obligated person, 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 the obligated person.

remedies, priority rights, or other similar terms of a Financial Obligation of the Authority, any of which affect security holders, if material

16. Default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Authority or any Obligated Project Participant (relating to its electric utility fund), any of which reflect financial difficulties.

APPENDIX E

PROPOSED FORM OF BOND COUNSEL OPINION

On the delivery date of the 2025 Series A Subordinate Bonds, Norton Rose Fulbright US LLP, Los Angeles, California, Bond Counsel, proposes to render its final approving opinion in substantially the following form:

[Delivery Date]

Board of Directors
Southern California Public Power Authority
1160 Nicole Court
Glendora, California 91740

Re: Southern California Public Power Authority
Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project)

Ladies and Gentlemen:

We have examined a record of proceedings relating to the issuance of $__________ aggregate principal amount of Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "2025 Series A Subordinate Bonds") by the Southern California Public Power Authority (the "Authority"), a public entity of the State of California, and such other matters of law as we have deemed necessary to enable us to render the opinions expressed herein.

The 2025 Series A Subordinate Bonds are issued under and 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, and Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of California (the "Act"). The 2025 Series A Subordinate Bonds are issued under and pursuant to an Indenture of Trust, dated as of [____] 1, 2025 (the "2025 Series A Subordinated Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee").

The 2025 Series A Subordinate Bonds are dated, and shall bear interest from, their date of delivery. Interest on the 2025 Series A Subordinate Bonds is payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2019. The 2025 Series A Subordinate Bonds mature and are subject to redemption (if applicable) prior to maturity as provided in the 2025 Series A Subordinated Indenture.

The 2025 Series A Subordinate Bonds will be issued in denominations of $5,000 or any integral multiple thereof. The 2025 Series A Subordinate Bonds will be issued in fully registered form, are exchangeable and transferable as provided in the 2025 Series A Subordinated Indenture, and are lettered and numbered as provided therein.

The 2025 Series A Subordinate Bonds are issued for the purpose of providing moneys to: (i) refund the Refunded Bonds (as defined in the Thirty-First Supplemental Indenture of Trust relating to the 2025 Series A Subordinate Bonds, dated as of [____] 1, 2025 (the "Supplemental Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee); and (ii) pay the costs of issuance of the 2025 Series A Subordinate Bonds. The Refunded Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 2015, from the Authority to U.S. Bank Trust Company, National

Association, as successor trustee, for the primary purpose of refinancing a portion of the cost of acquisition of capacity relating to the Southern Transmission Project. The 2025 Series A Subordinate Bonds are payable from Pledged Revenues (as defined in the 2025 Series A Subordinated Indenture) and the 2025 Series A Issue Fund and all accounts established therein relating to the 2025 Series A Subordinate Bonds, subject only to the provisions of the 2025 Series A Subordinated Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

The Authority has entered into six separate Transmission Service Contracts (the "Transmission Service Contracts") with the following purchasers (the "Project Participants") of transmission service utilizing Authority Capacity (as defined in the 2025 Series A Subordinated Indenture and the Indenture of Trust, dated as of May 1, 1983, from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (as amended and supplemented, the "Senior Indenture")): the Department of Water and Power of The City of Los Angeles and the Cities of Anaheim, Riverside, Pasadena, Burbank and Glendale.

Capitalized terms not defined herein shall have the respective meanings set forth in the Senior Indenture or the 2025 Series A Subordinated Indenture, as applicable.

From such examination, we are of the opinion that:

1. The Authority has been duly created and is validly existing under the provisions of the Act and has the right and authority under the Act to acquire and utilize Authority Capacity.

2. The Authority has the right and authority to enter into and carry out its obligations under the Transmission Service Contracts and has duly authorized, executed and delivered the Transmission Service Contracts which constitute valid and binding agreements of the Authority, enforceable in accordance with their terms.

3. The Authority has the right and authority under the Act to enter into the 2025 Series A Subordinated Indenture, the 2025 Series A Subordinated Indenture has been duly and lawfully authorized, executed and delivered by the Authority, and assuming due authorization, execution and delivery by, and enforceability against, the other party thereto, is in full force and effect in accordance with its terms and constitutes a valid and binding agreement of the Authority, enforceable in accordance with its terms, and no other authorization for the 2025 Series A Subordinated Indenture is required. The 2025 Series A Subordinated Indenture creates the valid pledge that it purports to create of (i) the Pledged Revenues and (ii) the 2025 Series A Issue Fund and all accounts established therein relating to the 2025 Series A Subordinate Bonds, subject only to the provisions of the 2025 Series A Subordinated Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

4. The Authority is duly authorized and entitled to issue the 2025 Series A Subordinate Bonds, and the 2025 Series A Subordinate Bonds have been duly and validly authorized and issued by the Authority in accordance with the Constitution and applicable statutes of the State of California, including the Act, and the 2025 Series A Subordinated Indenture. The 2025 Series A Subordinate Bonds constitute valid and binding obligations of the Authority as provided in the 2025 Series A Subordinated Indenture, are enforceable in accordance with their terms and the terms of the 2025 Series A Subordinated Indenture, and are entitled to the benefits of the 2025 Series A Subordinated Indenture. The 2025 Series A Subordinate Bonds are not an obligation of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants 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 2025 Series A Subordinate Bonds. The Authority has no taxing power.

5. Under the Constitution and laws of the State of California, each Transmission Service Contract constitutes a valid and binding agreement of the Project Participant party thereto 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 Transmission Service Contracts: (i) the legal existence or formation of any 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 Project Participant, including, without limitation, any proceedings relating to the negotiation or authorization of any Transmission Service Contract or the execution, delivery or performance thereof (except that we have examined the ordinances pursuant to which the respective Transmission Service Contracts were authorized by the respective Project Participants); (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Transmission Service Contracts) or any governmental order, regulation or rule of or applicable to any Project Participant; (iv) any judicial order, judgment or decree in a proceeding to which any 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 that may be or has been required for the authorization, execution, delivery or performance by any Project Participant of its 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 Transmission Service Contracts rendered by legal counsel to the respective Project Participants.

Our opinions are based on existing law, which is subject to change. We assume no duty to update or supplement our opinions to reflect any facts or circumstances that may hereafter come to our attention or to reflect any changes in any law that may hereafter occur or become effective.

No opinion is expressed herein on the accuracy, completeness or sufficiency of the Official Statement or other offering material relating to the 2025 Series A Subordinate Bonds.

The opinions expressed in paragraphs 2, 3, 4 and 5 hereof are qualified to the extent that the enforceability of the Senior Indenture, the 2025 Series A Subordinated Indenture, the 2025 Series A Subordinate Bonds and the Transmission Service Contracts may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights generally or as to the availability of any particular remedy. The enforceability of the Senior Indenture, the 2025 Series A Subordinated Indenture, the 2025 Series A Subordinate Bonds and the Transmission Service Contracts 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 governmental entities in California (including, but not limited to, rights of indemnification).

Respectfully submitted,

APPENDIX F

PROPOSED FORM OF SPECIAL TAX COUNSEL OPINION

On the delivery date of the 2025 Series A Subordinate Bonds, Nixon Peabody LLP, Los Angeles, California, Special Tax Counsel, proposes to render its opinion in substantially the following form:

[Delivery Date]

Southern California Public Power Authority
1160 Nicole Court
Glendora, CA 91740

Ladies and Gentlemen:

We have acted as special tax counsel to the Southern California Public Power Authority (the "Authority") in connection with the issuance of $__________ aggregate principal amount of its Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "Bonds").

The 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 May 1, 1983 (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 an Indenture of Trust, dated as of [_____] 1, 2025, from the Authority to the Trustee (the "2025 Series A Subordinated Indenture") and a Thirty-First Supplemental Indenture of Trust dated as of [____] 1, 2025, from the Authority to the Trustee (the "Thirty-First Supplemental Indenture of Trust," and together with the Indenture of Trust and the 2025 Series A Subordinated Indenture, the "Indenture").

Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture. In rendering the opinions set forth below, we have relied upon the approving opinions of Norton Rose Fulbright US LLP, Bond Counsel to the Authority, delivered on even date herewith, relating among other things to the validity of the Bonds.

The Bonds are being issued to provide funds to redeem all of the $89,480,000 outstanding aggregate principal amount of the Authority's Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C, which mature on July 1, 2025 through 2027, inclusive (the "Refunded Bonds"), which bonds were issued in 2015 to refinance a portion of the cost of acquisition of capacity relating to a capital improvement of the Southern Transmission System by refunding all of the Authority's Transmission Project Revenue Bonds, 2008 Subordinate Series B that were outstanding at the time that the Refunded Bonds were issued.

In our capacity as special tax counsel, we have reviewed the Act, the Indenture, the Authority's Tax Certificate as to Arbitrage and the Provisions of Sections 103 and 141-150 of the Internal Revenue Code of 1986 with respect to the Bonds (the "Tax Certificate"), certifications of the Authority, the Trustee, the Project Participants and others, opinions of counsel to the Authority, the Trustee and to each Project Participant, and such other documents, opinions and instruments as we deemed necessary to render the opinions set forth herein.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Authority, and, with respect to the Renewal Transmission Service Contracts, the Project Participants. We have not undertaken to verify independently, and have assumed, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions referred to in the third paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Renewal Transmission Service Contracts.

The Internal Revenue Code of 1986 (the "Code") sets forth certain requirements which must be met subsequent to the issuance and delivery of the 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 Bonds. Pursuant to the Indenture and the Tax Certificate, the Authority has covenanted to comply with each applicable requirement of the Code necessary to qualify the Bonds as obligations described in section 103(a) of the Code. In addition, the Authority has made certain representations and certifications in the Tax Certificate. We have not independently verified the accuracy of those certifications and representations.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

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 above, interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Code. We are also of the opinion that such amounts are not treated as a preference item in calculating the alternative minimum tax imposed under the Code.

We are also of the opinion that interest on the Bonds is exempt from personal income taxes of the State of California under present law.

Except as stated in the preceding two paragraphs, we express no opinion as to any other federal, state or local tax consequences of the ownership or disposition of the Bonds. Furthermore, we express no opinion as to any federal, state or local tax law consequences with respect to the Bonds, or the interest thereon, if any action is taken with respect to the Bonds or the proceeds thereof upon the advice or approval of other counsel.

Very truly yours,

APPENDIX G

ESTIMATED DEBT SERVICE REQUIREMENTS
(Accrual Basis)

Fiscal Year Ending June 30	2025 Series A Subordinate Bonds		Total
	Principal	Interest	Debt Service(1)
2025	$	$	$
2026			
2027			
Total(3)	$	$	$

(1) Totals may not foot due to rounding

NOTICE OF INTENTION TO SELL

$[PAR AMOUNT]*
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

NOTICE IS HEREBY GIVEN that the Southern California Public Power Authority (the "Authority") intends to offer for public sale, only through electronic bidding, at

[____], 2025
[8:00] a.m., California Time

(or such other date and at such other time as is announced via Ipreo) through the use of the Parity® electronic bid submission system of Ipreo, at www.newissuehome.i-deal.com the Authority's Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "Bonds"). No other means of delivery of bids will be accepted. The Authority reserves the right to postpone from time to time, or cancel, the sales, provided that notice of such change is given through Ipreo prior to such change, as described under "Postponement," "Right of Cancellation by Authority," and "Right to Modify or Amend" in the Notice Inviting Bids.

The Bonds are being issued by the Authority to provide moneys to refund all of the Authority's outstanding $89,480,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C and to pay costs of issuance relating to the Bonds.

The public sale and the right to submit a bid are subject to the terms and conditions of the Notice Inviting Bids. Electronic copies of the Notice Inviting Bids and the Preliminary Official Statement relating to the Bonds may be obtained by request to the Authority's Municipal Advisor, PFM Financial Advisors LLC; Telephone (213) 415-1624; Attention: Mike Berwanger.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Dated: [______], 2025

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* Preliminary, subject to change.

NOTICE INVITING BIDS

$[PAR AMOUNT]*
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

NOTICE IS HEREBY GIVEN that bids as described herein will be received by the Executive Director of the Southern California Public Power Authority (the "Authority"), or his designee, for the purchase of all, but not less than all, of the Authority's Transmission Project Revenue Bonds, 2025 Subordinate Refunding Series A (Southern Transmission Project) (the "Bonds"), more particularly described herein.

The bids will be received in the form, in the manner and up to the time specified below (unless postponed or cancelled as described herein):

Date and Time:	[____], 2025 [8:00] a.m., California time
Electronic Bids:	Electronic proposals may be submitted through the BiDCOMP™/PARITY® electronic bid submission system of Ipreo, at www.newissuehome.i-deal.com. Ipreo will act as agent of the bidder and not of the Authority in connection with the submission of bids, and the Authority assumes no responsibility or liability for bids submitted through Ipreo's system. See "Electronic Bidding" herein.
No Facsimile, Hand Delivery or Sealed Bids:	No facsimile, hand delivery or sealed bids will be accepted.

No bid will be received after the applicable time specified above. To the extent any instructions or directions set forth in Ipreo conflict with this Notice Inviting Bids, the terms of this Notice Inviting Bids shall control. Further information about Ipreo, including qualification, registration, rules and any fee charged, may be obtained from Ipreo at (877) 588-5030.

Capitalized terms used in this Notice Inviting Bids and other otherwise defined have the meanings given in the Preliminary Official Statement.

Type of Bid Allowed

Subject to the bid requirements described in this Notice Inviting Bids, conforming bids for the Bonds may be submitted on only an "all-or-none" basis for all of the Bonds, and if such bid is

* Preliminary, subject to change.

accepted by the Authority, the bidder will be required to purchase all of the Bonds in accordance with such bid. All bids must be unconditional.

Receipt of Bids and Award of Bonds

Bids will be received in electronic form only and solely through the electronic bid submission system of Ipreo. The Authority reserves the right to reject any and all bids and to waive any irregularity or error in any bid. No bid may be withdrawn after the time set for the closing of bids. The bids will be received at the above time and date. The Executive Director, or his designee, acting on behalf of the Authority, will take official action awarding the Bonds or rejecting all bids with respect to the Bonds not later than 2 hours after the time established for receipt of bids for the Bonds, unless such time period is waived by the winning bidder.

Purpose of the Bond Issues

The Bonds are being issued by the Authority to provide moneys to refund all of the Authority's outstanding $89,480,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the "Refunded Bonds") and to pay costs of issuance relating to the 2025 Series A Subordinate Bonds.

Authority for Issuance

The 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 Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of the State of California, and pursuant to an Indenture of Trust, dated as of [_________] 1, 2025 (the "Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as trustee (the "Trustee").

Bidders are referred to the Indenture and the Preliminary Official Statement for definitions of terms and further information regarding the Bonds.

Security; Limited Obligations

As described in additional detail below and in the Preliminary Official Statement, principal of, premium, if any, and interest on the Bonds will be payable from certain moneys in the General Reserve Fund under the Indenture of Trust, dated as of May 1, 1983 (the "Original Indenture"), from the Authority to U.S. Bank Trust Company, National Association, as successor trustee (the "Senior Indenture Trustee"), as supplemented and amended (the "Senior Indenture"), including as supplemented and amended by the Thirty-First Supplemental Indenture of Trust relating to the 2025 Series A Subordinate Bonds, dated as of [_________] 1, 2025 (the "Thirty-First Supplemental Indenture"), that are transferred to funds held under the Indenture. See "SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE 2025 SERIES A SUBORDINATE BONDS" in the Preliminary Official Statement.

In addition to the Bonds and Senior Bonds (as defined in the Preliminary Official Statement), if any, additional subordinate bonds that rank on a parity with the Bonds, may be issued by the Authority. Currently, the Authority has no Senior Bonds outstanding and no plans to issue Senior Bonds. Upon the issuance of the Bonds and the defeasance of the Refunded Bonds, there will be no other subordinate bonds payable on parity with the Bonds. Further, interest rate swap agreements and certain other types of agreements ("Parity Swaps") payable on a parity with the Bonds (other than with respect to termination payments thereunder, which shall be payable on a basis subordinate and junior to the Bonds) may be entered into by the Trustee, the Authority and the provider of any such agreement. See "SUMMARY OF CERTAIN DOCUMENTS – SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE – Application of Revenues" and "– SUMMARY OF CERTAIN PROVISIONS OF THE 2025 SERIES A SUBORDINATED INDENTURE – Application of Pledged Revenues" in Appendix C to the Preliminary Official Statement.

The Indenture provides that the Authority has pledged and assigned to the Trustee, for the benefit of the Owners of the Bonds and any Parity Swap Providers, (i) the Pledged Revenues and (ii) the 2025 Series A Issue Fund and all Accounts therein established by the Indenture, subject only to the provisions of the Indenture and the Thirty-First Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture and the Thirty-First Supplemental Indenture. Upon delivery, the Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or redemption price, if applicable, thereof and interest thereon, in accordance with their terms and the provisions of the Indenture and the Thirty-First Supplemental Indenture, solely by the moneys, Fund and Accounts set forth in clauses (i) and (ii) of this paragraph.

"Pledged Revenues" with respect to the Bonds are all Available Revenues transferred to and deposited in the 2025 Series A Pledged Revenues Account pursuant to the Senior Indenture (including the Thirty-First Supplemental Indenture).

"Available Revenues" are all moneys and funds at any time on deposit in the General Reserve Fund established by the Senior Indenture and not required to meet a deficiency under the Senior Indenture or required by the Senior Indenture to be used for payment, purchase or redemption of Senior Bonds.

The Senior Indenture provides that the Senior Indenture will remain outstanding for so long as any Senior Bonds, the Bonds or Notes of the Authority with respect to the Southern Transmission Project remain outstanding.

"Revenues" under the Senior Indenture are (i) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to Authority Capacity or to the payment of the costs thereof received or to be received by the Senior Indenture Trustee under the Transmission Service Contracts or under any other contract for the sale by the Authority of Authority Capacity or any part thereof or any contractual arrangement with respect to the use of Authority Capacity or any portion thereof or the services or capacity thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to Authority Capacity, (iii) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Senior Indenture and required to be paid into the Revenue Fund, (iv) interest received on any moneys or securities held pursuant to the 2025 Series A Subordinated Indenture and required by its terms to be paid into the Revenue Fund, (v) amounts received by or on behalf of the Authority pursuant to any Parity Swap, (vi) amounts received by or on behalf of the Authority pursuant to any subordinate swap agreement or similar agreement that provides therein (including in any schedule or attachment thereto) that payments received by or on behalf of the Authority pursuant thereto shall constitute Revenues under the Senior Indenture, and (vii) amounts received by or on behalf of the Authority pursuant to any Cap Agreement (as defined in the Senior Indenture).

After application if and as required for certain purposes under the Senior Indenture (including without limitation the General Reserve Fund thereunder), on or before the last business day of each calendar month, Available Revenues, to the extent required to be deposited into the funds and accounts established under the Indenture for such month, are to be transferred ratably from amounts remaining in the General Reserve Fund by the Senior Indenture Trustee to the Trustee for deposit in the 2025 Series A Pledged Revenues Account. Moneys set aside to meet the requirements of the Indenture (or any future subordinated indenture) shall be applied in a manner such that none shall have priority over or otherwise rank prior to the others. Available Revenues upon their deposit in the 2025 Series A Pledged Revenues Account become Pledged Revenues, free and clear of the lien and pledge of the Senior Indenture.

The Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants (as defined in the Preliminary Official Statement), and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of any of the Bonds. The Bonds shall not constitute 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.

No Funded 2025 Series A Reserve Account

Pursuant to the Indenture, the Reserve Requirement for the Bonds shall be equal to $0.00, and the 2025 Series A Reserve Account will not be funded.

No Municipal Bond Insurance

[THE SUCCESSFUL BIDDER SHALL NOT PURCHASE MUNICIPAL BOND INSURANCE IN CONNECTION WITH THE BONDS.]

Book-Entry Only

The Bonds will be issued as fully registered bonds and, when issued, will be initially registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as security depository for the Bonds. Individual purchases of the Bonds will be made in book-entry form only, in denominations of $5,000 principal amount or any integral multiple thereof. Payments of principal of, interest and premium, if any, on the Bonds will be paid by the Trustee to DTC, which is obligated in turn to remit such principal, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the Bonds.

Interest Payment Dates

The Bonds will be dated the Issue Date, and interest will be payable semiannually on each January 1 and July 1, commencing July 1, 2025.

Principal Amortization

The Bonds shall be subject to principal amortization through serial maturities (and, if applicable, as provided herein, term bonds) maturing on July 1 in the following years and amounts subject to the adjustments described herein:

July 1	Principal Amount*
2025	$[_____]
2026	
2027	

* Preliminary, subject to adjustments as described herein. In addition, the Authority anticipates distributing an updated Maturity Schedule prior to the date scheduled for the receipt of bids, as described under "Adjustment of Principal Amounts and Amortization Schedule."

Adjustment of Principal Amounts and Amortization Schedule

The principal amounts for the Bonds set forth in this Notice Inviting Bids reflect certain estimates of the Authority and its Municipal Advisor with respect to the likely interest rates of the winning bid and the net original issue premium contained in the winning bid. The principal amortization schedule (the "Maturity Schedule") may be changed prior to the time bids are to be received and, if adjustments are made, bidders must bid on the basis of the adjusted schedule. Potential bidders will be notified via Ipreo not later than 1:00 p.m. (California time) on the business day preceding the date then prescribed for the receipt of bids of any change to the Maturity Schedule for the Bonds to be utilized for the bidding process.

After selecting the winning bid, the principal amount of the Bonds and related amortization schedule may be adjusted by the Authority in $5,000 increments as necessary in the determination of the Authority's Municipal Advisor to reflect the actual interest rates and any net original issue premium in the winning bid and to achieve the Authority's debt structuring objectives. Any such adjustment will be communicated to the winning bidder within four hours after acceptance of the winning bid.

NO PURCHASER MAY WITHDRAW ANY BID OR CHANGE THE INTEREST RATES IN ITS BID OR THE REOFFERING PRICES IN ITS ISSUE PRICE CERTIFICATE AS A RESULT OF ANY CHANGE MADE TO THE PRINCIPAL PAYMENTS OF THE BONDS

IN ACCORDANCE WITH THIS NOTICE INVITING BIDS. FURTHER, IF THE AUTHORITY CHANGES THE MATURITY SCHEDULE FOR THE BONDS AFTER THE RECEIPT OF BIDS, THE UNDERWRITER'S DISCOUNT, EXPRESSED IN DOLLARS PER THOUSAND DOLLAR, WILL BE HELD CONSTANT. THE AUTHORITY WILL NOT BE RESPONSIBLE, IF AND TO THE EXTENT THAT, ANY ADJUSTMENT AFFECTS (i) THE NET COMPENSATION TO BE REALIZED BY THE PURCHASER OR (ii) THE TRUE INTEREST COST OF THE WINNING BID OR THE RANKING OF ANY BID RELATIVE TO OTHER BIDS.

[Serial Bonds and/or Term Bonds; Mandatory Sinking Fund Redemption

Bidders may elect to structure the issue to include term bonds, which term bonds, if selected by the winning bidder, will be subject to mandatory sinking fund redemption prior to maturity, in the years and amounts shown above (as same may be adjusted, as described above). If the Bonds are awarded to a bidder and no term bonds are designed in the winning bid, the Bonds will mature serially as shown in the preceding schedule (as same may be adjusted, as described above).

If the winning bidder designates principal amounts to be combined into one or more term bonds, each such term bond shall be subject to mandatory sinking fund redemption commencing on July 1 of the first year which has been combined to form such term bond and continuing on July 1 in each year thereafter until the stated maturity date of that term bond. The amount redeemed in any year shall be equal to the principal amount for such year set forth in the table above under "Principal Amortization," as adjusted in accordance with the provisions described above under "Adjustment of Principal Amounts and Amortization Schedule." Bonds to be redeemed in any year by mandatory sinking fund redemption shall be redeemed in part at par and shall be selected by lot from among the Bonds of the applicable maturity then subject to sinking fund redemption. The Authority, at its option, may credit against any mandatory sinking fund redemption requirement term bonds of the maturity then subject to redemption which have been purchased and cancelled by the Authority or have been redeemed and not theretofore applied as a credit against any mandatory sinking fund redemption requirement.]

No Optional Redemption

The Bonds are not subject to redemption prior to maturity.

Trustee

U.S. Bank Trust Company, National Association, Los Angeles, California, is the Trustee for the payment of principal of, premium, if any, and interest on the Bonds and for the registration of the Bonds.

Legal Opinions

The legal opinions of Norton Rose Fulbright US LLP, Bond Counsel, and Nixon Peabody LLP, Special Tax Counsel, will be furnished to the winning bidder at the time of delivery of the Bonds, without charge to the winning bidder.

Bidding Procedure; Confirmation of Bid

Only electronic bids submitted via Ipreo will be accepted. No other provider of electronic bidding services will be accepted. No bid delivered in person or by facsimile directly to the Authority will be accepted. Each electronic bid submitted via Ipreo for the purchase of the Bonds shall be deemed an offer to purchase the Bonds in response to this Notice Inviting Bids, and shall be binding upon the bidder as if made by a signed, sealed bid delivered to the Authority. The successful bidder must confirm the details of such bid by a signed copy of Appendix A of this Notice Inviting Bids delivered by email to the Authority's Municipal Advisor at berwangerm@pfm.com and carbonej@pfm.com immediately after being notified by the Authority of being the winning bidder, the original of which must be received by the Executive Director of the Authority, or his designee, on the following business day at the address shown on Appendix A of this Notice Inviting Bids. Failure to deliver this confirmation does not relieve the bidder of its obligation to complete the purchase of the Bonds.

Electronic Bidding

Electronic proposals must be submitted through Ipreo. If any provision of this Notice Inviting Bids conflicts with information provided by Ipreo, this Notice Inviting Bids shall control. Each bidder will be solely responsible for making necessary arrangements to access Ipreo for purposes of submitting its bid in a timely manner and in compliance with the requirements of this Notice Inviting Bids. The Authority will not have any duty or obligation to provide or assure access to Ipreo to any bidder, and the Authority will not be responsible for proper operation of, or have any liability for, any delays, interruptions or damages caused by use of Ipreo or any incomplete, inaccurate or untimely bid submitted by any bidder through Ipreo. The Authority is permitting use of Ipreo as a communication mechanism, and not as an agent of the Authority, to facilitate the submission of electronic bids for the Bonds. Ipreo is acting as an independent contractor, and is not acting for or on behalf of the Authority. The Authority is not responsible for ensuring or verifying bidder compliance with any procedures established by Ipreo. The Authority may regard the electronic transmission of a bid through Ipreo (including information regarding the purchase price for the Bonds or the interest rates for any maturity of the Bonds) as though the information were submitted and executed on the bidder's behalf by a duly authorized signatory. The Authority is not bound by any advice of or determination by Ipreo to the effect that any particular bid complies with the terms of this Notice Inviting Bids. All costs and expenses incurred by prospective bidders in connection with their submission of bids through Ipreo are the sole responsibility of such bidders, and the Authority is not responsible for any such costs or expenses. Further information about Ipreo, including any fee charged to the bidder, may be obtained from Ipreo at (877) 588-5030. The Authority assumes no responsibility or liability for bids submitted through Ipreo. Without limiting the foregoing, the Authority assumes no responsibility for any error contained in any bid submitted electronically or for failure of any bid to be transmitted, received or opened by the time for receiving bids, and each bidder expressly assumes the risk of any incomplete, illegible, untimely or nonconforming bid submitted by electronic transmission by such bidder, including, without limitation, by reason of garbled transmissions, mechanical failure, engaged telecommunications lines, or any other cause arising from submission by electronic transmission. The Authority shall be entitled to assume that any bid submitted Ipreo has been made by a duly authorized agent of the bidder.

All-or-None Bids Only

Bidders only may bid to purchase all maturities of the Bonds. See Appendix A hereto. No bid will be considered which does not offer to purchase all of the Bonds. Each bid must specify an annual rate of interest, a reoffering price and a reoffering yield for each maturity and a dollar purchase price for the entire issue of the Bonds.

Interest Rates and Minimum Purchase Price

Bidders must specify a rate of interest for each maturity of the Bonds. The rates of interest must be expressed in multiples of one-eighth (1/8) or one-twentieth (1/20) of one percent (1%), and no interest rate can exceed [six percent (6.0%)] per annum. **All Bonds of the same maturity must bear the same rate of interest. A zero rate of interest cannot be named. No bid that contains a reoffering price for any single maturity of less than [100%] of the par will be considered.**

Bid Procedure and Basis of Award

Subject to the right reserved to the Authority to reject any or all bids, the Bonds will be sold to the bidder whose bid produces the lowest True Interest Cost for the Authority and otherwise complies with this Notice Inviting Bids. The True Interest Cost for the Bonds will be determined by doubling the semi-annual interest rate, using a 360-day year, compounded semiannually, necessary to discount the semi-annual debt service payments from their respective payment dates to the dated date of the Bonds and to the aggregate purchase price to be paid to the Authority. For the purpose of calculating the True Interest Cost, the principal amount of Bonds established for mandatory sinking fund redemption as part of a term bond shall be treated as a serial maturity in each year. **The maximum interest rate on any maturity of Bonds shall not exceed [six percent (6.0%)] per annum.**

Bid Security and Delivery and Payment for Bonds

A bid security (good faith deposit) is required in the amount of $[____] for the Bonds. Bid security must be in the form of a wire transfer to the Authority as instructed by the Municipal Advisor, no later than 24 hours after the Authority has notified the successful bidder of the award. If not so received, the bid of the lowest bidder will be rejected and the Authority may direct the second lowest bidder to submit a Good Faith Deposit and thereafter may award the sale of the Bonds to the same. No interest on the bid security will accrue to the winning bidder. The bid security will be applied to the purchase price of the Bonds. If the winning bidder fails to purchase the Bonds, the bid security may be retained by the Authority.

The balance of the purchase price for the Bonds shall be paid in Federal Funds or equivalent immediately available funds. Notwithstanding the foregoing, should a winning bidder fail to pay for the Bonds awarded to it at the price and on the date agreed upon, the Authority retains the right to seek further compensation for damages sustained as a result.

Delivery of the Bonds is expected to occur on the Issue Date. The Bonds shall be delivered to the Trustee for deposit with DTC. Payment on the delivery date shall be made in an amount equal to the price bid for the Bonds awarded to the applicable bidder, less the amount of the bid security provided by such bidder.

Information Required from Winning Bidders

By making a bid for the Bonds, the winning bidder agrees (a) to provide to the Authority, in writing, immediately upon being unofficially awarded the Bonds, a written confirmation of the bid in the form set forth in Appendix A of this Notice Inviting Bids, which shall include the purchase price, reoffering yield(s), and other related information necessary for completion of the final Official Statement, (b) to disseminate to all members of the underwriting syndicate, if any, copies of the final Official Statement, (c) to promptly file a copy of the final Official Statement with Municipal Securities Rulemaking Board, and (d) to take any and all other actions necessary to comply with applicable Securities and Exchange Commission and Municipal Securities Rulemaking Board rules governing the offering, sale and delivery of the Bonds to ultimate purchasers.

Establishment of Issue Price (Hold-the-Offering Price Rule Will Apply if Competitive Sale Requirements are Not Satisfied).

(a) The winning bidder shall assist the Authority in establishing the issue price of the Bonds and shall execute and deliver to the Authority by the closing date an issue price certificate substantially in the form set forth in Appendix B hereto setting forth the reasonably expected initial offering price to the public, together with the supporting pricing wires or equivalent communications, with such modifications as may be appropriate or necessary, in the reasonable judgment of the winning bidder, the Authority and Bond Counsel. All actions to be taken by the Authority under this Notice Inviting Bids to establish the issue price of the Bonds may be taken on behalf of the Authority by the Authority's Municipal Advisor identified herein and any notice or report to be provided to the Authority may be provided to the Authority's Municipal Advisor.

(b) The Authority intends that the provisions of Treasury Regulation Section 1.148-1(f)(3)(i) (defining "competitive sale" for purposes of establishing the issue price of the Bonds) will apply to the initial sale of the Bonds (the "competitive sale requirements") because:

(1) the Authority shall disseminate this Notice Inviting Bids to potential underwriters in a manner that is reasonably designed to reach potential underwriters;

(2) all bidders shall have an equal opportunity to bid;

(3) the Authority may receive bids from at least three underwriters of municipal bonds who have established industry reputations for underwriting new issuances of municipal bonds; and

(4) the Authority anticipates awarding the sale of the Bonds to the applicable bidder who submits a firm offer to purchase the Bonds at the highest price (or lowest interest cost), as set forth in this Notice Inviting Bids.

Any bid submitted pursuant to this Notice Inviting Bids shall be considered a firm offer for the purchase of the Bonds, as specified in the bid.

(c) In the event that the competitive sale requirements for the Bonds are not satisfied, the Authority shall so advise the winning bidder. In such event, the Authority intends to treat the initial offering price to the public as of the sale date of each maturity of the Bonds as the issue price of that maturity (the "hold-the-offering-price rule"). The Authority shall promptly advise the winning bidder, at or before the time of award of the Bonds, if the competitive sale requirements were not satisfied, in which case the hold-the-offering-price rule shall apply to the Bonds. Bids will not be subject to cancellation in the event that the competitive sale requirements are not satisfied and the hold-the-offering-price rule applies. In the event that the competitive sale requirements are not satisfied, the issue price certificate shall be modified as necessary in the reasonable judgment of Bond Counsel and the Authority.

(d) By submitting a bid, the winning bidder shall (i) confirm that the underwriters have offered or will offer the Bonds to the public on or before the date of award at the offering price or prices (the "initial offering price"), or at the corresponding yield or yields, set forth in the bid submitted by the winning bidder and (ii) agree, on behalf of the underwriters participating in the purchase of the Bonds, that the underwriters will neither offer nor sell unsold Bonds of any maturity to which the hold-the-offering-price rule applies 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 Bonds to the public at a price that is no higher than the initial offering price to the public.

Such winning bidder will advise the Authority promptly after the close of the fifth (5th) business day after the sale date whether it has sold 10% of that maturity of the Bonds to the public at a price that is no higher than the initial offering price to the public.

(e) The Authority acknowledges that, in making the representations set forth above, the winning bidder will rely on (i) the agreement of each underwriter to comply with the requirements for establishing 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, (ii) 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 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 a selling group agreement and the related pricing wires, and (iii) in the event that an underwriter or 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 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. The Authority further acknowledges that each underwriter shall be solely liable for its failure to comply with its agreement regarding the requirements for establishing 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 to comply with the requirements for establishing issue price of the Bonds, including, but not limited to, its agreement to comply with the hold-the-offering-price rule as applicable to the Bonds.

(f) By submitting a bid, each bidder confirms that:

(1) any agreement among underwriters, any selling group agreement and each third-party distribution agreement (to which the bidder 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 comply with the hold-the-offering-price rule, if applicable, if and for so long as directed by the winning bidder and as set forth in the related pricing wires,

(2) any agreement among underwriters or selling group agreement 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 or dealer 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 comply with the hold-the-offering-price rule, if applicable, if and for so long as directed by the winning bidder or the underwriter and as set forth in the related pricing wires.

(g) Sales of any Bonds to any person that is a related party to an underwriter shall not constitute sales to the public for purposes of this Notice Inviting Bids. Further, for purposes of this section of the Notice Inviting Bids:

(1) "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,

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

(3) "underwriter" means (A) any person that agrees pursuant to a written contract with the Authority (or with the lead underwriter to form an underwriting syndicate) to participate in the initial sale of the Bonds to the public and (B) any person that agrees pursuant to a written contract directly or indirectly with a person described in clause (A) 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),

(4) 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 (A) 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), (B) 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 (C) 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

(5) "sale date" means the date that the Bonds are awarded by the Authority to the winning bidder.

Preliminary and Final Official Statement

The Authority has approved a Preliminary Official Statement, dated [____], 2025, which the Authority has "deemed final" for purposes of Rule 15c2-12 (the "Rule") of the Securities and Exchange Commission, although subject to revision, amendment and completion in a final Official Statement in conformity with such Rule. All bidders must review the Preliminary Official Statement (and any amendments or supplements thereto) prior to participating in the bidding.

Within seven (7) business days after the date of award of the Bonds, the winning bidder of the Bonds will be furnished with a reasonable number of copies (not to exceed 200) of the Official Statement, without charge. If the purchaser requests additional copies of the Official Statement within two (2) days after the award of the Bonds, the Authority will supply such requested additional copies of the Official Statement at the expense of the purchaser. The purchaser of the Bonds may elect to receive the Official Statement in electronic form.

Continuing Disclosure

To assist bidders in complying with the Rule, the Authority will undertake, pursuant to a Continuing Disclosure Undertaking, to provide certain annual financial information and notices of the occurrence of certain enumerated events. A form of the Continuing Disclosure Undertaking is set forth in the Preliminary Official Statement and will also be set forth in the final Official Statement. See "CONTINUING DISCLOSURE UNDERTAKING FOR THE 2025 SERIES A SUBORDINATE BONDS" in the Preliminary Official Statement.

Certificate

The Authority will provide to the winning bidder of the Bonds a certificate, signed by a responsible officer, confirming that, at the time of the acceptance of its bid for the Bonds and at the time of delivery of the Bonds, the Preliminary Official Statement and the final Official

Statement (together with any amendments or supplements), respectively, did 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 (with customary exceptions for certain information contained in the Official Statement).

Right of Rejection

The Authority reserves the right, in its discretion, to reject any and all bids, including any bids not conforming to this Notice Inviting Bids or not in the form of the Official Bid Form, and to waive any irregularity or informality in any bid.

Prompt Award

The Authority will award the Bonds or reject all bids not later than two hours after the expiration of the time herein prescribed for the receipt of proposals, unless such time of award is waived by the winning bidder.

California Debt and Investment Advisory Commission

The winning bidder will be required to pay any fees relating to the Bonds due to the California Debt and Investment Advisory Commission ("CDIAC") under California law.

Blue Sky Laws

The winning bidder of the Bonds will be responsible for the payment of any fees for qualification of the Bonds for sale under the securities or "Blue Sky" laws of any state. The winning bidder may not offer to sell, or solicit any offer to buy, Bonds in any jurisdiction where it is unlawful for such winning bidder to make such offer, solicitation or sale, and the winning bidder shall comply with the Blue Sky and other securities laws and regulations of the states and jurisdictions in which the winning bidder sells the Bonds. Bidders shall not offer to sell or solicit an offer to buy, nor shall the winning bidder sell any Bonds, in any jurisdiction where the Blue Sky or other securities laws and regulations of such jurisdiction require the payment of a fee prior to taking any such action if such fee has not been paid.

CUSIP Numbers

It is anticipated that CUSIP numbers will be printed on the Bonds, but neither the failure to print such numbers on any Bond nor any error with respect thereto shall constitute cause for a failure or refusal by the winning bidder thereof to accept delivery of and pay for the Bonds in accordance herewith. The Authority's Municipal Advisor shall apply for CUSIP numbers in a timely manner. All expenses for the assignment and printing of CUSIP numbers for the Bonds shall be paid by the Authority.

No Litigation

At the time of delivery of the 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 Bonds or the collection of Pledged Revenues, or in any way questioning or affecting (i) the proceedings under which the Bonds are to be issued, (ii) the validity of any provision of the Bonds, the Senior Indenture or the Indenture, (iii) the pledge by the Authority under the Indenture, (iv) the validity or enforceability of the 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 Project.

Tax-Exempt Status

If after the date of this Notice Inviting Bids but prior to the delivery of the Bonds (i) the interest received by any private holder from bonds of the same type and character as the Bonds shall be declared to be taxable (either at the time of such declaration or at any future date) under any federal income tax laws, by the terms of such law or by ruling of a federal income tax authority or official which is followed by the Internal Revenue Service, or by decision of any federal court, or (ii) any federal income tax law is enacted which will have a substantial adverse tax effect on owners of the Bonds as such owners, the winning bidder may, at its option, prior to the tender of the Bonds by the Authority, be relieved of its obligation to purchase the Bonds awarded to it and in such case the bid security provided by such bidder will be returned.

Modification, Postponement or Cancellation of Sale

The Authority reserves the right to modify, postpone or cancel the sale of the Bonds at or prior to the time bids are to be received with respect to the Bonds. Notice of such modification, postponement or cancellation will be given through Ipreo as soon as practicable following such modification, postponement or cancellation. If the sale is postponed, notice of a new sale date will be given through Ipreo prior to the time that bids are to be received. On any new sale date, any bidder may submit a bid for the purchase of Bonds, which shall be in conformity in all respects with the provisions of this Notice Inviting Bids except for the time or date and time of sale and any other changes announced through Ipreo.

Failure of any potential bidder to receive notice of modification, cancellation or postponement shall not affect the sufficiency of any such notice or affect the Authority's right to take the action described herein. If a sale is postponed only, any subsequent bid submitted by a bidder with respect to such sale will supersede any prior bid made. If a sale is cancelled, all bids with respect to such sale will be deemed cancelled.

Right of Cancellation by Winning Bidder

The winning bidder of the Bonds shall have the right, at its option, to cancel its obligation to purchase the Bonds awarded to it if the Authority shall fail to execute the Bonds and tender the same for delivery within 60 days from the date of award thereof, and in such event such winning bidder shall be entitled to the return of its bid security.

Additional Information

This Notice Inviting Bids, the Preliminary Official Statement and the Official Bid Form may be obtained from Ipreo. Copies of the Indenture and the Senior Indenture (including the Thirty-First Supplemental Indenture) will be furnished to any potential bidder upon request made to the Authority's Municipal Advisor, PFM Financial Advisors LLC, Attention: Mike Berwanger, telephone: (213) 415-1642.

Date: [_____], 2025

Executive Director,
Southern California Public Power Authority

APPENDIX A

OFFICIAL BID FORM

[TO BE DELIVERED BY THE WINNING BIDDER]

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

________________, 2025

Southern California Public Power Authority
c/o Executive Director
1160 Nicole Court
Glendora, California 91740

Ladies and Gentlemen:

Subject to the provisions of and in accordance with the terms of the Notice Inviting Bids, dated [_____], 2025, of the Southern California Public Power Authority (the "Authority") for its above-referenced bonds (the "Bonds"), which Notice Inviting Bids is incorporated herein and hereby made a part hereof:

We hereby confirm that we have agreed to purchase all, but not less than all, of the $____________ aggregate principal amount of Bonds described in the Notice Inviting Bids and to pay therefor the amount of $____________ constituting _____% (which percent is not less than [100%]) of the par amount of the Bonds. .

This offer is for the Bonds bearing interest at the rates and in the form of serial bonds and, if applicable, term bonds as follows:

Balance of page intentionally left blank.

July 1	Principal Amount*	Interest Rate	Reoffering Price	Reoffering Yield	[Term Maturity Date (Check if applicable.)]
	$				

* Aggregate principal amount and principal amortization amounts may be adjusted by the Authority as set forth in the Notice Inviting Bids.

In the event the "competitive sale requirements" set forth in the Notice Inviting Bids are not met, we agree to comply with the hold-the-offering price rule described in the Notice Inviting Bids.

We acknowledge and agree that after we submit this proposal, the Authority may modify the aggregate principal amount of the Bonds and/or the principal amount of each maturity of the Bonds, subject to the limitations set forth in the Notice Inviting Bids.

We further acknowledge and agree that in the event that any adjustments are made to the principal amount of the Bonds, we will purchase all of the Bonds, taking into account such adjustments on the above specified terms of this bid for the Bonds.

As the winning bidder, we confirm that we have agreed to wire $[____] to the Authority as provided in the Notice Inviting Bids, as security against the undersigned bidder's failure to comply with the terms of the bid.

As the winning bidder, we confirm that we have agreed to immediately furnish the additional information described under the caption "Information Required from Winning Bidder" in the Notice Inviting Bids. As the winning bidder, we will (1) within 30 minutes after being notified of the verbal award of the Bonds, advise the Authority of the initial public offering prices of the Bonds; and (2) prior to delivery of the Bonds furnish a certificate, acceptable to Special Tax Counsel, Nixon Peabody LLP, as to the "issue price" of the Bonds in the form specified in the Notice Inviting Bids.

As the winning bidder, we confirm that we have agreed to provide to the Authority as soon as possible after the sale of the Bonds a complete list of syndicate members, if any, the actual allocation of the Bonds and the orders placed by the syndicate members, if any.

We have noted that payment of the purchase price of the Bonds is to be made in immediately available Federal Funds at the time of delivery of the Bonds.

If we have bid on behalf of a bidding syndicate, we represent that we have full and complete authority to submit the bid on behalf of our bidding syndicate and that the undersigned will serve as the lead manager for the group.

Only electronic copies of the final Official Statement for the Bonds will be provided to the winning bidder.

We further certify and declare under penalty of perjury under the laws of the State of California that our bid and this proposal are genuine and not a sham or collusive, nor made in the interest of or on behalf of any person not herein named, and that the bidder has not directly or indirectly induced or solicited any other bidder to put in a sham bid or any other person, firm or corporation to refrain from bidding, and that the bidder has not in any manner sought by collusion to secure for itself an advantage over any other bidder . Further, we did not consult with any other potential underwriter about this bid, and this bid was determined by us, independently, without regard to any other formal or informal agreement, if any, that we may have with the Authority (whether or not in connection with the sale and issuance of the Bonds).

Respectfully submitted,

____
Name of Bidder

By:___________________________

Name and Title:_________________

(Names of other syndicate account members, if any, are listed below.)

SYNDICATE ACCOUNT MEMBERS

APPENDIX B

[TO BE DELIVERED BY THE WINNING BIDDER]

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2025 Subordinate Refunding Series A
(Southern Transmission Project)

ISSUE PRICE CERTIFICATE

The undersigned, on behalf of ______________ (the "**Purchaser**"), hereby certifies as set forth below with respect to the sale of the above-captioned obligations (the "**Bonds**") of the Southern California Public Power Authority (the "Authority").

1. ***Reasonably Expected Initial Offering Price***.

(a) As of the Sale Date, the reasonably expected initial offering prices of the Bonds to the Public by the Purchaser are the prices listed in Schedule A (the "**Expected Offering Prices**"). The Expected Offering Prices are the prices for the Maturities of the Bonds used by the Purchaser in formulating its bid to purchase the Bonds. Attached as **Schedule B** is a true and correct copy of the bid provided by the Purchaser to purchase the Bonds.

(b) The Purchaser was not given the opportunity to review other bids prior to submitting its bid.

(c) The bid submitted by the Purchaser constituted a firm offer to purchase the Bonds.

2. ***Defined Terms***.

(a) *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.

(b) *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.

(c) *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 __________, 2025.

(d) *Underwriter* means (i) any person that agrees pursuant to a written contract with the Authority (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 or other third-party distribution agreement participating in the initial sale of the Bonds to the Public).

The representations set forth in this certificate are limited to factual matters only. Nothing in this certificate represents the Purchaser'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 Authority with respect to certain of the representations set forth in the tax certificate with respect to the Bonds and with respect to compliance with the federal income tax rules affecting the Bonds, and by Norton Rose Fulbright US LLP 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 the Internal Revenue Service Form 8038-G, and other federal income tax advice that it may give to the Authority from time to time relating to the Bonds.

[PURCHASER]

By: ________________________________

Name:

Title:

Dated: ____________ __, 2025

SCHEDULE A

EXPECTED OFFERING PRICES

(*Attached*)

SCHEDULE B

COPY OF UNDERWRITER'S BID

(*Attached*)

SCPPA
Southern California Public Power Authority

AGENDA ITEM STAFF REPORT

MEETING DATE: December 19, 2024 **RESOLUTION NUMBER:** 2024-110

SUBJECT: Southern Transmission System (STS) Renewal Project Revenue Bonds (Third 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	☐	N/A	
Executive Director	☐		

MEMBER PARTICIPATION:

Sponsoring Member: LADWP, Burbank and Glendale

Other Members Potentially Participating: None

Approved by Executive Director: Signed by: DAE0F3A6ECDE496...

RECOMMENDATION:

Adopt a Resolution authorizing the preparation of all documents necessary for the sale and issuance of the third tranche of project revenue bonds for the Southern Transmission System (STS) Renewal Project.

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 $2.7 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 May 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 second tranche of bonds was issued in May 2024 with the issuance of the Southern Transmission System Renewal Project, Revenue Bonds, 2024-1 for $562,855,000. The two tranches will cover approximately $1.2 billion in project costs through June 2025. The balance of $1.5 billion is anticipated to be funded with two additional tranches of bonds, the third and fourth tranches. The current estimated in-service dates of the upgraded facilities and total project costs are trending with the projections for the second tranche of bonds.

With the need for additional bond proceeds after June 2025, SCPPA staff recommend that the work to prepare the necessary documents to issue the third tranche of bonds be started. Similar to the first two tranches, the proposed financing plan anticipates issuing fixed rate tax-exempt project revenue bonds structured with approximately level aggregate debt service to final maturity in 2053. Staff are currently working with the project team to firm up the estimated construction spending through June 2026, which will determine the bond size of the third tranche.

On December 2, 2024, the Finance Committee discussed the issuance of the third tranche of bonds for the STS Renewal Project and recommended bringing this Resolution to the Board of Directors (Board) for approval to authorize the preparation of all necessary documents for the sale and issuance of revenue bonds for the project.

SCPPA will incur costs in connection with municipal advisor, bond counsel, and tax counsel services for the preparation of the documents and related activities. These costs will be included in the total amount of bonds issued as bond issuance costs. The payment of municipal advisor, bond counsel, and tax counsel fees will be contingent on the successful closing of the transaction. Once the draft documents have been prepared, they will be brought to the Board for consideration and approval at a future meeting of the Board.

- **Selection Method:**

  The selection of the financing team will be done in accordance with SCPPA's Policy for Financing and Selection of the Financing Team (Policy) and will consider the criteria as provided in the Policy to determine the underwriting firm(s) that will deliver the overall best value for the transaction.

- **Environmental Review:**

  The proposed Resolution would authorize the preparation of documents for financing to fund the STS Renewal Project previously approved by the Board and Project Participants and determined to be exempt from the California Environmental Quality Act (CEQA) by the Project Participants. The Board's action is exempt from CEQA 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:

There is no immediate fiscal impact. Interest during the construction period will be capitalized. The debt service for each component facility will start as each facility is placed in service. Prior to the transition date of June 16, 2027, 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 IPA, in proportion to their respective capacity rights in the existing STS Project. Debt service payments from Project Participants under the Renewal Transmission Service Contracts will start after the transition date of June 16, 2027.

ATTACHMENT:

1. Resolution No. 2024-110

[Project Vote: LADWP, Glendale and Burbank]

RESOLUTION NO. 2024-110

RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY (I) AUTHORIZING THE PREPARATION OF ALL DOCUMENTS NECESSARY OR APPROPRIATE TO SELL AND ISSUE SOUTHERN TRANSMISSION SYSTEM RENEWAL PROJECT, REVENUE BONDS, PROCEEDS OF WHICH WILL BE USED TO FINANCE PAYMENTS-IN-AID OF CONSTRUCTION FOR THE STS RENEWAL PROJECT AND (II) AUTHORIZING OFFICERS OF THE AUTHORITY TO DO ALL THINGS DEEMED NECESSARY OR APPROPRIATE

WHEREAS, the Southern California Public Power Authority (the "Authority") has heretofore issued bonds and other debt obligations to finance and refinance payments-in-aid of construction for certain electric power transmission facilities known as the Southern Transmission System (the "Existing Southern Transmission System"); and

WHEREAS, the Authority has heretofore issued bonds to finance payments-in-aid of construction for the STS Renewal Project, which consists of major improvements to capacity in the Existing Southern Transmission System in connection with the repowering of the Intermountain Power Project (the "STS Renewal Project"); and

WHEREAS, the Finance Committee of the Authority has determined that it is in the best interest of the Authority to proceed with preparing all documents necessary or appropriate to sell and issue one or more additional series of debt obligations (the "Bonds"), the proceeds of which will be used to finance payments-in-aid of construction for the STS Renewal Project; and

WHEREAS, once prepared, drafts of the contracts proposed to be entered into by the Authority in connection with the issuance of the Bonds will be presented for the Board's consideration.

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

1. The Authority's staff and the Authority's team of financing professionals (including the personnel at the Los Angeles Department of Water and Power who work on Authority matters, the Authority's Bond Counsel, the Authority's Special Tax Counsel and the Authority's Municipal Advisor) are hereby authorized to prepare all documents necessary or appropriate for the sale and issuance of the Bonds.

2. Each of the President, any Vice President, Executive Director, Chief Financial and Administrative Officer, Secretary, any Assistant Secretary, any other officer of the Authority, and any designee of the President, any Vice President, the Executive Director or the Chief Financial

and Administrative Officer, is hereby authorized and directed to do and cause to be done any and all acts and things deemed necessary or appropriate for carrying out the transactions contemplated by this Resolution.

3. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority this 19th day of December, 2024.

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TIKAN SINGH
PRESIDENT
Southern California Public
Power Authority

ATTEST:

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DANIEL E GARCIA
ASSISTANT SECRETARY
Southern California Public
Power Authority

[Project Vote: LADWP, Glendale]

RESOLUTION NO. 2024-111

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APPROVING THE **REVISED** ANNUAL BUDGET FOR
ELAND SOLAR & STORAGE CENTER, PHASE I PROJECT
FOR THE FISCAL YEAR
JULY 1, 2024 THROUGH JUNE 30, 2025

BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority (the "Authority") that:

1. The revised budget for the Eland Solar & Storage Center Phase I Project for the Fiscal Year July 1, 2024 through June 30, 2025, 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 Eland Solar & Storage Center, Phase I 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, 2024 through June 30, 2025.

2. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 19th day of December, 2024.

TIKAN SINGH
PRESIDENT
Southern California Public
Power Authority

ATTEST:

DANIEL E GARCIA
ASSISTANT SECRETARY
Southern California Public
Power Authority

ANNUAL BUDGET
July 1, 2024 through June 30, 2025
Eland Solar 1 + Storage Project
($000)
Revision No. 1

Month	Test Energy Payments	PPA Payments	PPA Expense Payment	Project Manager	Working Capital	Direct Admin. & General	Indirect Admin. & General	**Total Cost of Power**	Estimated Energy (MWH) to be Scheduled
Jul	$1,002	$0	$0	$3	$250	$4	$8	**$1,267**	22,879
Aug	$1,002	$0	$0	$3	$250	$4	$8	**$1,267**	88,948
Sep	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	79,103
Subtotal	$2,004	$2,668	$0	$9	$750	$12	$24	**$5,467**	190,930
Oct	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	67,460
Nov	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	49,568
Dec	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	42,120
Subtotal	$0	$8,004	$0	$9	$750	$12	$24	**$8,799**	159,148
Jan	$0	$2,668	$4,120	$3	$250	$4	$8	**$7,053**	45,232
Feb	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	51,280
Mar	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	77,432
Subtotal	$0	$8,004	$4,120	$9	$750	$12	$24	**$12,919**	173,945
Apr	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	80,158
May	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	90,209
Jun	$0	$2,668	$0	$3	$250	$4	$8	**$2,933**	90,891
Subtotal	$0	$8,004	$0	$9	$750	$12	$24	**$8,799**	261,258
Total FY	$2,004	$26,680	$4,120	$36	$3,000	$48	$96	**$35,984**	785,281

ANNUAL BUDGET
July 1, 2024 through June 30, 2025
Eland Solar 1 + Storage Project
($000)
Revision No. 1

	Revenues			Revenue Fund Disbursements		
Month	Monthly Power Costs	Interest Earnings (4)	Total Revenues	Operating Fund	Reserve Account	Total Revenue Fund Dis-bursements
Jul	$1,267	$0	$1,267	$1,267	$0	$1,267
Aug	$1,267	$0	$1,267	$1,267	$0	$1,267
Sep	$2,933	$0	$2,933	$2,933	$0	$2,933
Subtotal	$5,467	$0	$5,467	$5,467	$0	$5,467
Oct	$2,933	$0	$2,933	$2,933	$0	$2,933
Nov	$2,933	$0	$2,933	$2,933	$0	$2,933
Dec	$2,933	$0	$2,933	$2,933	$0	$2,933
Subtotal	$8,799	$0	$8,799	$8,799	$0	$8,799
Jan	$7,053	$0	$7,053	$7,053	$0	$7,053
Feb	$2,933	$0	$2,933	$2,933	$0	$2,933
Mar	$2,933	$0	$2,933	$2,933	$0	$2,933
Subtotal	$12,919	$0	$12,919	$12,919	$0	$12,919
Apr	$2,933	$0	$2,933	$2,933	$0	$2,933
May	$2,933	$0	$2,933	$2,933	$0	$2,933
Jun	$2,933	$0	$2,933	$2,933	$0	$2,933
Subtotal	$8,799	$0	$8,799	$8,799	$0	$8,799
0	$35,984	$0	$35,984	$35,984	$0	$35,984

[Project Vote: LADWP]

RESOLUTION NO. 2024-112

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APPROVING THE **REVISED** ANNUAL BUDGET FOR
ELAND SOLAR & STORAGE CENTER, PHASE II PROJECT
FOR THE FISCAL YEAR
JULY 1, 2024 THROUGH JUNE 30, 2025

BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority (the "Authority") that:

1. The revised budget for the Eland Solar & Storage Center Phase II Project for the Fiscal Year July 1, 2024 through June 30, 2025, 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 Eland Solar & Storage Center, Phase II 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, 2024 through June 30, 2025.

2. This Resolution shall become effective immediately.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 19th day of December, 2024.

TIKAN SINGH
PRESIDENT
Southern California Public
Power Authority

ATTEST:

DANIEL E GARCIA
ASSISTANT SECRETARY
Southern California Public
Power Authority

ANNUAL BUDGET
July 1, 2024 through June 30, 2025
Eland Solar 2 + Storage Project
($000)
Revision No. 1

Month	Test Energy Payments	PPA Payments	PPA Expense Payment	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**	0
Aug	$0	$0	$0	$0	$0	$0	$0	**$0**	0
Sep	$0	$0	$0	$0	$0	$0	$0	**$0**	0
Subtotal	$0	$0	$0	$0	$0	$0	$0	**$0**	0
Oct	$397	$0	$0	$4	$334	$4	$0	**$739**	16,286
Nov	$397	$0	$0	$4	$334	$4	$0	**$739**	20,214
Dec	$397	$0	$0	$4	$334	$4	$0	**$739**	29,811
Subtotal	$1,191	$0	$0	$12	$1,002	$12	$0	**$2,217**	66,311
Jan	$926	$0	$4,120	$4	$334	$4	$0	**$5,388**	36,186
Feb	$926	$0	$0	$4	$334	$4	$0	**$1,268**	41,024
Mar	$926	$0	$0	$4	$334	$4	$0	**$1,268**	61,945
Subtotal	$2,778	$0	$4,120	$12	$1,002	$12	$0	**$7,924**	139,156
Apr	$0	$3,497	$0	$4	$334	$4	$0	**$3,839**	64,126
May	$0	$3,497	$0	$4	$334	$4	$0	**$3,839**	72,167
Jun	$0	$3,497	$0	$4	$334	$4	$0	**$3,839**	72,713
Subtotal	$0	$10,491	$0	$12	$1,002	$12	$0	**$11,517**	209,006
Total FY	$3,969	$10,491	$4,120	$36	$3,006	$48	$0	**$21,658**	414,473

ANNUAL BUDGET
July 1, 2024 through June 30, 2025
Eland Solar 2 + Storage Project
($000)
Revision No. 1

	Revenues			Revenue Fund Disbursements		
Month	Monthly Power Costs	Interest Earnings	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	$739	$0	$739	$739	$0	$739
Nov	$739	$0	$739	$739	$0	$739
Dec	$739	$0	$739	$739	$0	$739
Subtotal	$2,217	$0	$2,217	$2,217	$0	$2,217
Jan	$5,388	$0	$5,388	$5,388	$0	$5,388
Feb	$1,268	$0	$1,268	$1,268	$0	$1,268
Mar	$1,268	$0	$1,268	$1,268	$0	$1,268
Subtotal	$7,924	$0	$7,924	$7,924	$0	$7,924
Apr	$3,839	$0	$3,839	$3,839	$0	$3,839
May	$3,839	$0	$3,839	$3,839	$0	$3,839
Jun	$3,839	$0	$3,839	$3,839	$0	$3,839
Subtotal	$11,517	$0	$11,517	$11,517	$0	$11,517
0	$21,658	$0	$21,658	$21,658	$0	$21,658