NOTICE OF **REGULAR** MEETING

CITY OF ALAMEDA PUBLIC UTILITIES BOARD

Alameda Municipal Power Service Center
2000 Grand Street, Conference Room A/B
(Corner of Clement Avenue)
Alameda, CA 94501

Monday, January 12, 2026 at 6:00 P.M.

Notice: Members of the public can attend and comment in-person, follow the meeting via web (http://bit.ly/4ploT8c) and teleconference (+1 510-358-3865 Conference ID: 297 420 175#***) and address the Public Utilities Board during the meeting via email (pub@alamedamp.com) or via live comments during the web/teleconference, except as noted otherwise on this agenda. For those participating via the web application, attendees can use the raise hand icon to indicate they are requesting the opportunity to make live comments. For those attendees who are calling in via telephone only, the Clerk will advise them when to unmute themselves. Comments submitted during the meeting will be read into the record (subject to speaker time limits). Comments submitted prior to the meeting will be included in the meeting record. Comments submitted through the Microsoft Teams meeting chat window will not be monitored. Any requests for reasonable accommodations from individuals with disabilities should be made by contacting Alameda Municipal Power at wise@alamedamp.com.***

The Board may take action on any item listed on the agenda.

1. ROLL CALL

2. ORAL COMMUNICATIONS - NON AGENDA (PUBLIC COMMENT)

   Members of the public are invited to address the Board on any subject related to the activities of Alameda Municipal Power not otherwise appearing on the Agenda; comments are limited to in-person only, remote public comment is not available for this section.

3. SPECIAL PRESENTATION

4. CONSENT CALENDAR

   Consent Calendar items are considered routine and will be enacted, approved or adopted by one motion unless a request for removal for discussion or explanation is received from the Board or a member of the public.

4.I. A. Minutes Of The December 8, 2025, Regular Meeting Of The City Of Alameda Public Utilities Board

Documents:

CONSENT CALENDAR ITEM A.PDF

4.II. B. Listing Of Bills Paid – December 2025

Documents:

CONSENT CALENDAR ITEM B.PDF

4.III. C. Financial Report – November 2025

Documents:

CONSENT CALENDAR ITEM C.PDF

4.IV. D. Treasurer's Report For The Month Ending November 30, 2025

Documents:

CONSENT CALENDAR ITEM D.PDF

4.V. E. By Motion, Accept The Independent Audit And Its Associated Reports From Maze & Associates Of Alameda Municipal Power's Financial Position For The Fiscal Year Ending On June 30, 2025, And Find The Action Exempt From The California Environmental Quality Act

Documents:

CONSENT CALENDAR ITEM E.PDF

4.VI. F. By Motion, Recommend City Council Approve The Upgrade Of One Customer Service Representative Position To Lead Customer Service Representative Classification, The Upgrade Of The Procurement Analyst Classification To Senior Procurement Analyst, And The Reclassification Of Senior Clerk To Administrative Services Coordinator, And Find The Action Exempt From The California Environmental Quality Act

Documents:

CONSENT CALENDAR ITEM F.PDF

4.VII. G. By Motion, Authorize The Purchase Of One Brooks Brothers Three-Reel Trailer For An Amount Not To Exceed $136,600 And Find The Action Exempt From The California Environmental Quality Act

Documents:

CONSENT CALENDAR ITEM G.PDF

5. AGENDA ITEMS

5.I. A. By Motion, Accept Alameda Municipal Power's Load Forecast For Fiscal Year 2027, And Find The Action Exempt From The California Environmental Quality Act

Documents:

AGENDA ITEM A.PDF

5.II. B. By Motion, Authorize The General Manager To Transfer Funds Within The Capital Improvement Budget And Execute A Transmission Facilities Agreement With Pacific Gas And Electric Company For The Line Current Differential Relaying Transmission Protection Project Between Jenney Substation And Oakland Station J In An Amount Not To Exceed $ 7,511,477, With A Contingency Of $308,523, For A Total Amount Not To Exceed $7,820,000 And Find The Action Exempt From The California Environmental Quality Act

Documents:

AGENDA ITEMB.PDF

6. GENERAL MANAGER'S REPORT

6.I. A. General Manager's Report – December 2025

Documents:

GENERAL MANAGER REPORT.PDF

7. COUNCIL COMMUNICATIONS

8. BOARD COMMUNICATIONS

9. ORAL COMMUNICATIONS - NON AGENDA (PUBLIC COMMENT)

Members of the public are invited to address the Board on any subject related to the activities of Alameda Municipal Power not otherwise appearing on the Agenda; comments are limited to in-person only, remote public comment is not available for this section.

10. ADJOURNMENT

- Each member of the public who wishes to speak is afforded up to 5 minutes per agenda item, which may be increased or limited by the presiding officer.
- Sign language interpreters will be available on request. Please contact Hayley Wise at 510-748-3908 or 510-522-7538 (TDD number) or EMAIL at least 72 hours before the meeting to request an interpreter.
- Accessible seating for persons with disability (including those using wheelchairs) is available.
- Minutes of the meeting are available in enlarged print.
- Audiotapes of the meeting are available upon request.
- Please contact Hayley Wise at 510-748-3908 or 510-522-7538 (TDD number) or EMAIL at least 72 hours prior to the meeting to request agenda materials in an alternative format, or any other reasonable accommodation that may be necessary to participate in and enjoy the benefits of the meeting.

Documents related to this agenda are available for public inspection and copying at Alameda Municipal Power's Service Center - 2000 Grand Street during office hours.

Know Your Rights Under the Sunshine Ordinance

Government's duty is to serve the public, reaching its decisions in full view of the public.

Commissions, boards, councils and other agencies of the City of Alameda exist to conduct the citizen of Alameda's business. This ordinance assures that deliberations are conducted before the people and that City operations are open to the people's review.

For more information on your rights under the sunshine ordinance or to report a violation of the ordinance, contact the Open Government Commission:

- 2263 Santa Clara Avenue
  Room 380
  Alameda, CA, 94501
- Phone: 510-747-4800
- Fax: 510-865-4048
- EMAIL CITY CLERK LARA WEISIGER

In order to assist the City's efforts to accommodate persons with severe allergies, environmental illnesses, multiple chemical sensitivity or related disabilities, attendees at public meetings are reminded that other attendees may be sensitive to various chemical based products. Please help the City accommodate these individuals.

[Section 2-91.13 (d) - Sunshine Ordinance]

DRAFT MINUTES OF THE REGULAR MEETING
CITY OF ALAMEDA PUBLIC UTILITIES BOARD

December 8, 2025

1. ROLL CALL

President McKenna called the meeting to order at 6:01 p.m. On roll call, the following commissioners were present: President McKenna, Commissioner Hunter, Commissioner Bird, Commissioner de Vries, and Interim City Manager Politzer.

2. ORAL COMMUNICATIONS – NON-AGENDA (Public Comment)

None.

3. SPECIAL PRESENTATIONS

A. Presentation of the Power Up For Learning Program with Alameda Education Foundation

Following a presentation by Julia Owens, Executive Director of the Alameda Education Foundation, the Board provided comments.

Commissioner Hunter expressed her thanks for the Power Up For Learning (PUFL) program and noted the ease at which AMP customers could sign up to donate through their bill.

Commissioner Bird asked if donations have been consistent over time. Ms. Owens noted that donors and donations amounts have been similar over the years.

Commissioner de Vries inquired if PUFL supports any specific programs that aren’t supported otherwise, and Ms. Owens pointed out the internet hot spots are funded by PUFL.

Interim City Manager Politzer asked the average donation and Ms. Owens replied the average donation is five dollars per month.

President McKenna offered the Board’s expertise as energy and engineering professionals to meet and knowledge share with Alameda Education Foundation’s beneficiaries.

Following the comments, the Board joined Ms. Owens and Alameda Education Foundation board member Grace Caulfield for a check presentation photo opportunity.

4. <u>CONSENT CALENDAR</u>

A. Minutes of the November 17, 2025, Regular Meeting of the City of Alameda Public Utilities Board

B. Listing of Bills Paid – November 2025

C. Financial Report – October 2025

D. Treasurer's Report for the Month Ending October 31, 2025

E. By Motion, Authorize a Transfer of Funds Within the Capital Improvement Budget of $175,000 to Cover the Fiscal Year 2026 Costs for the Cartwright Substation Battery and Battery Charger Replacement Project, and Find the Action Exempt from the California Environmental Quality Act

Interim City Manager Politzer recused himself from Item 4A. Following a motion from Commissioner de Vries and a second from Commissioner Hunter, the Board unanimously approved the consent calendar.

5. <u>AGENDA ITEMS</u>

A. For Information and Feedback only, Update to Alameda Municipal Power's Strategic Plan Revisit

Following a presentation by Teri Alderson, Assistant General Manager (AGM) of Administration, the Board began discussion.

Commissioner de Vries noted his support for public engagement regarding this project and noted his interest in learning if the survey will show a shift in the public's priorities.

Commissioner Bird thanked AMP staff for providing the Board with updates throughout the feedback process.

Commissioner Hunter asked if there were key demographics that AMP would like to hear from, and AGM Alderson noted key audiences as previously discussed by the Board. Commissioner Hunter looks forward to seeing what aspects of AMP resonate most with customers.

President McKenna inquired about the structure and intended audiences for the focus groups. AGM Alderson explained that AMP's consultant, GreatBlue Research, will conduct the virtual focus groups and would target specific demographics.

This item is for information only.

6. GENERAL MANAGER’S REPORT

General Manager Haines provided an update on the tree trimming policy enacted earlier in the year, and this has resulted in fewer tree-related outages.

7. CITY COUNCIL COMMUNICATIONS

None.

8. BOARD COMMUNICATIONS

None.

9. ORAL COMMUNICATIONS – NON-AGENDA (Public Comment)

None.

10. ADJOURNMENT

President McKenna adjourned the meeting at 6:46 p.m.

Alameda Municipal Power
Alameda, California
From Check Date: 12/01/2025 - To Check Date: 12/31/2025
The following bills payable out of the Alameda Municipal Power funds were approved for payment.

SUPPLIER	DESCRIPTION	AMOUNT
NO CALIF POWER AGENCY	ALL POWER BILL-DEC2025(P)	2,745,792.00
SMITH DENISON CONSTRUCTION CO	UNDERGROUND38(O)	2,084,856.36
HILLTOP	INVESTMENTS(G)	1,000,000.00
ALAMEDA, CITY OF	PAYROLL(A)	647,327.96
ALAMEDA, CITY OF	PAYROLL(A)	637,693.68
ALAMEDA, CITY OF	PAYROLL(A)	574,181.23
ALAMEDA, CITY OF	GENERAL FUND TRANSFER(A)	460,326.00
ALAMEDA, CITY OF	UTILITY TAX(A)	393,465.27
U S BANK TRUST NA	2010A&B SERIES REVENUE BOND(A)	218,060.98
ALAMEDA, CITY OF	AMP PERS UNFUNDED LIABILITY(A)	180,601.92
ALAMEDA, CITY OF	PILOT & ROI CHARGES(A)	140,416.67
HOWARD INDUSTRIES, INC.	ELECTRICAL SPLYS(I)	118,585.36
ALAMEDA, CITY OF	COST ALLOCATION(A)	64,166.25
PHYLLIS E. CURRIE	CONSULTANT(A)	39,870.39
ONE SOURCE SOLUTIONS, LLC	ELECTRICAL SPLYS(I)	34,110.34
WEST COAST ARBORISTS, INC	TREE TRIMMING(O)	33,040.00
PAYMENTUS CORP	TRANSACTION FEES(A)	30,670.72
1835 ALAMEDA PROPERTY LLC	LEASE-BLDG(A)	30,377.88
CARLSON SALES	ELECTRICAL SPLYS(I)	30,301.20
ANIXTER INC.	ELECTRICAL SPLYS(I)	25,362.52
SCHWEITZER ENGINEERING LAB.	ELECTRICAL SPLYS(O)	23,600.65
SUMMIT TECHNOLOGY, INC.	ELECTRICAL SPLYS(O)	20,887.23
GENERAL PACIFIC INC	ELECTRICAL SPLYS(I)	19,564.97
ALAMEDA CHAMBER OF COMMERCE	MEMBERSHIP(M)	15,000.00
MASTERSON ADVISORS LLC	FINANCIAL ADVISORY FEE(A)	15,000.00
DATAPROSE, LLC.	PRINTING SVCS(A)	12,852.46
UTIL-ASSIST INC.	STAFFING SUPPORT(A)	10,539.00
THE HAWKINS COMPANY	PROFESSIONAL FEE(G)	10,000.00
NORTHWEST LINEMAN COLLEGE	TRAINING(O)	8,850.00
U.S. BANK IMPAC GOV. SVCS	CAL CARD PAYMENT(V)	8,460.85
ALAMEDA, CITY OF	AMP CALPERS HEALTH(A)	6,816.59
MELISSA CHOW	USED ELECTRIC VEHICLE RBT(P)	6,000.00
MELISSA GAZZANEO	USED ELECTRIC VEHICLE RBT(P)	6,000.00
STEPHANE BARILE	USED ELECTRIC VEHICLE RBT(P)	6,000.00
SUCCESSMETRICS CORP	SOFTWARE(C)	5,980.00
LANDIS+GYR TECHNOLOGY, INC	DATA SVCS(A)	5,268.42
INDUSTRIAL SAFETY LLC	SAFETY SPLYS(O)	4,717.92
NORTHWEST LINEMAN COLLEGE	TRAINING(O)	4,575.00
GLOBAL RENTAL CO. INC.	VEHICLE RENTAL(O)	3,806.48
GRAINGER INC	ELECTRICAL SPLYS(G)	3,523.79
SHI	SOFTWARE(A)	3,501.49
GMES LLC	ELECTRICAL SPLYS(I)	3,359.90
ASSOCIATION FOR ENERGY AFFORDABILIT	BUILDING ELECT TECH SVCS(P)	3,321.50
CINTAS CORPORATION	UNIFORMS(O)	3,046.47
BLAISDELLS	OFFICE SPLYS(I)	3,045.07
FIONA BARRIAC	REFUND (O)	2,906.61
HARRISON ENGINEERING INC.	UNDERGROUND UTILITY(O)	2,647.67
SHI	COMPUTER SPLYS(A)	2,643.45
LAURA AERNI	USED ELECTRIC VEHICLE RBT(P)	1,950.00

Alameda Municipal Power
Alameda, California
From Check Date: 12/01/2025 - To Check Date: 12/31/2025
The following bills payable out of the Alameda Municipal Power funds were approved for payment.

SUPPLIER	DESCRIPTION	AMOUNT
ROBERTA HOUGH	HEAT PUMP HVAC REBATE(P)	1,900.00
ZONES, INC	SOFTWARE(A)	1,720.00
ELS	AQUATIC CENTER DESIGN(G)	1,717.50
TJ-H2B ANALYTICAL SERVICES	TESTING SVCS(O)	1,678.00
ENERSYS DELAWARE INC	ELECTRICAL SPLYS(O)	1,658.74
CSG CONSULTANTS, INC.	UNDERGROUND38(O)	1,560.00
ALEX CHAN	HEAT PUMP HVAC REBATE(P)	1,500.00
ALEXANDRA WANIGATUNGA	HEAT PUMP HVAC REBATE(P)	1,500.00
EDMOND NG	USED ELECTRIC VEHICLE RBT(P)	1,500.00
EMILY PAVELLE	PANEL UPGRADE REBATE(P)	1,500.00
HARRISON KURTZ	HEAT PUMP HVAC REBATE(P)	1,500.00
JAMIE MCPHERSON	HEAT PUMP HVAC REBATE(P)	1,500.00
JOSHUA SMITH	HEAT PUMP HVAC REBATE(P)	1,500.00
JOYCE FAHEY	HEAT PUMP HVAC REBATE(P)	1,500.00
REBECCA TIEMENS	HEAT PUMP HVAC REBATE(P)	1,500.00
RONALD GEE	USED ELECTRIC VEHICLE RBT(P)	1,500.00
TRAVIS MORGAN	HEAT PUMP HVAC REBATE(P)	1,500.00
GLOBAL RENTAL CO. INC.	VEHICLE RENTAL(O)	1,251.24
E B M U D	WATER CHARGES(A)	1,225.30
SUN-NET INC.	MONTHLY FEE(A)	1,083.33
DE LAGE LANDEN FINANICAL SVCS	COPIER LEASE(A)	1,005.97
STATE ROOFING SYSTEMS INC.	ROOF REPAIRS(A)	988.20
GEOGRAPH TECHNOLOGIES LLC	TRAINING(A)	950.00
WILLIAMS WELDING CO.	WELDING SVCS(O)	900.00
ELISE HUNTER	EXPENSE REIMB(G)	850.04
SKC-WEST,INC.	ELECTRICAL SPLYS(G)	833.84
CHRISTINA MCKENNA	EXPENSE REIMB(G)	832.38
SELECT FIRST AID & SAFETY	FIRST AID SPLYS(G)	821.00
STERICYCLE, INC.	SHREDDING SVCS(A)	807.11
THAI LY	EXPENSE REIMB(A)	642.19
ALAMEDA, CITY OF	WORKERS COMP(A)	616.95
UNITED PARCEL SERVICES	SHIPPING(A,M)	591.34
JUDY YEUNG	EXPENSE REIMB(A)	586.27
ALAMEDA MEALS ON WHEELS	SPONSORSHIP(M)	500.00
ALAMEDA POST INC.	SPONSORSHIP(M)	500.00
ALAMEDA POST INC.	SPONSORSHIP(M)	500.00
GIRLS INC OF THE ISLAND CITY	SPONSORSHIP(M)	500.00
JENNIFER CHIN	INDUCTION COOKTOP REBATE(P)	500.00
LAURA ADAMS	EV CHARGER REBATE(P)	500.00
LAUREN KELLEY	EV CHARGER REBATE(P)	500.00
ZACH KAHL	INDUCTION COOKTOP REBATE(P)	500.00
TERESA MARTYNY	EV CHARGER REBATE(P)	494.00
ERIK JOHANNESSEN	EV CHARGER REBATE(P)	489.00
GAUTHAM HEGDE	EV CHARGER REBATE(P)	450.00
TIMOTHY HAINES	MEALS (G)	432.67
ISHMAEL RILES	EV CHARGER REBATE(P)	429.00
ROBERT FERNANDEZ	EV CHARGER REBATE(P)	429.00
WOSSEN WORKNEH	EV CHARGER REBATE(P)	407.55
PACIFIC GAS AND ELECTRIC	PILOT WIRE OWNERSHIP FEE(A)	386.20

Alameda Municipal Power
Alameda, California
From Check Date: 12/01/2025 - To Check Date: 12/31/2025
The following bills payable out of the Alameda Municipal Power funds were approved for payment.

SUPPLIER	DESCRIPTION	AMOUNT
EPLUS TECHNOLOGY INC	COMPUTER SPLYS(A)	305.02
ALEXANDRA AMINOFF	INDUCTION COOKTOP REBATE(P)	300.00
JAMAL SMITH	E-BIKE REBATE(P)	300.00
KALLE LINDGREN	E-BIKE REBATE(P)	300.00
ROSE MEYER	INDUCTION COOKTOP REBATE(P)	300.00
ALAMEDA ELECTRICAL DISTR.	ELECTRICAL SPLYS(O)	266.77
KAISER FOUNDATION HEALTH PLAN	PHYSICALS(O)	230.00
ROLLINS, INC	PEST CONTROL(A)	225.00
ROLLINS, INC	PEST CONTROL(A)	195.00
ABAG POWER	GASOLINE CHARGES(A)	189.06
BAY STAMP & ENGRAVING LLC	ENGRAVING SVCS(A)	172.77
NORTHWEST LINEMAN COLLEGE	TRAINING(O)	150.00
NORTHWEST LINEMAN COLLEGE	TRAINING(O)	150.00
ROLLINS, INC	PEST CONTROL(A)	130.00
AT&T	PHONE SVCS(A)	126.28
SAL TAFAOA,	HOSE ASSEMBLY (O)	125.58
ROLLINS, INC	PEST CONTROL(A)	125.00
BLAISDELLS	OFFICE SPLYS(V)	124.10
PAGANO'S HARDWARE TOWNE CENTRE	HARDWARE(V)	105.09
CHERYL NG	E-BIKE REBATE(P)	100.00
JONATHAN MILLS	E-BIKE REBATE(P)	100.00
MARINEL MAGANTE	E-BIKE REBATE(P)	100.00
VALERIE WILSON	E-BIKE REBATE(P)	100.00
ALAMEDA MAIL BOXES PLUS	COMMISSIONS(C)	66.90
BLAISDELLS	OFFICE SPLYS(O)	64.76
NO CALIFORNIA JT POLE ASSO	MONTHLY ASSESSMENT(O)	55.94
JOHN NARVAEZ	MEALS(O)	38.00
RADC ENTERPRISES, INC.	CAR WASHES(O)	36.00
CALEB PHILLIPS	MEALS(O)	35.44
ROSS NATON	MEALS (O)	32.10
MARK REGAN	MEALS (O)	28.65
HAYLEY WISE	PLATES AND DRINKS(G)	21.45
BLAISDELLS	OFFICE SPLYS(A)	9.72
		9,765,917.70

The above claims in the amount of $9,765,917.70
have been examined, certified correct, and approved
for payment by the secretary of the Public Utilities Board.

/S/

Secretary of the Public Utilities Board

AGENDA ITEM NO: 4.C.1
MEETING DATE: 1/12/2026

ALAMEDA MUNICIPAL POWER

A Department of the City of Alameda

Monthly Financial Report

with data through November 2025 (Unaudited)

The data contained in this report has not been independently audited.

AGENDA ITEM NO: 4.C.2
MEETING DATE: 1/12/2026

Alameda Municipal Power
Financial Report
With Supporting
Documentation For the
Month of November 2025

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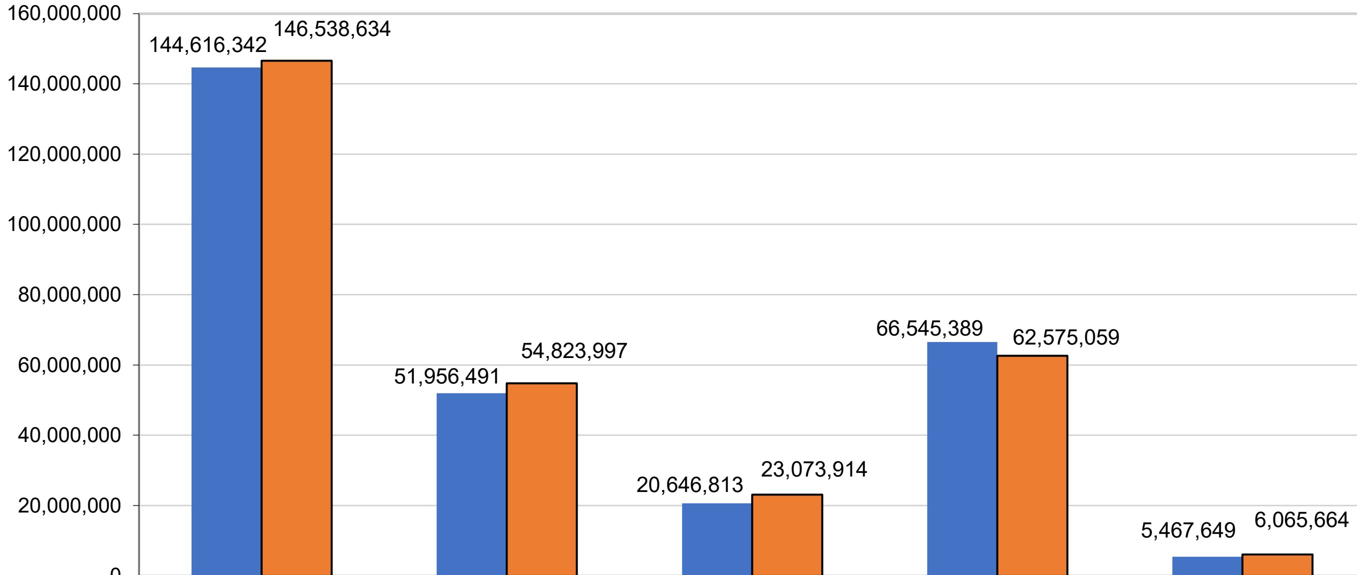
MANAGEMENT SUMMARY

Alameda Municipal Power
Financial Summary of Selected Totals
For the Period Ending November 2025

	Actual - Year-to-Date	Budget - Year-to-Date	Over (Under) Budget	% Variance	Prior Year Actual - Year-to-Date	Prior Year Over (Under)	% Variance
Residential (D1 & D2)	51,956,491	54,823,997	(2,867,506)	**-5.2%**	52,789,667	(833,176)	**-1.6%**
General Service (A1)	20,646,813	23,073,914	(2,427,101)	**-10.5%**	22,843,594	(2,196,781)	**-9.6%**
Demand Metered (A2 & A3)	66,545,389	62,575,059	3,970,330	**6.3%**	65,639,752	905,637	**1.4%**
Municipal & Other (M1, M2, M3, OL, CT&VG)	5,467,649	6,065,664	(598,015)	**-9.9%**	5,982,817	(515,168)	**-8.6%**
Electric Sales (KWH):	**144,616,342**	**146,538,634**	**(1,922,292)**	**-1.3%**	**147,255,830**	**(2,639,488)**	**-1.8%**
Commercial & Industrial	***87,192,202***	***85,648,973***	***1,543,229***	***1.8%***	***88,483,346***	***(1,291,144)***	***-1.5%***
Excess Solar Generation	***(1,606,281)***	***-***		***NA***	***(1,825,008)***	***218,727***	***NA***
Residential (D1 & D2)	13,098,773	14,003,056	(904,283)	-6.5%	12,677,743	421,030	3.3%
General Service (A1)	4,916,011	5,497,410	(581,399)	-10.6%	5,238,357	(322,345)	-6.2%
Demand Metered (A2 & A3)	12,845,963	12,196,385	649,578	5.3%	12,259,124	586,839	4.8%
Municipal & Other (M1, M2, M3, OL, CT&VG)	1,227,545	1,375,389	(147,844)	-10.7%	1,301,974	(74,428)	-5.7%
Electric Sales	***32,088,294***	***33,072,240***	***(983,946)***	***-3.0%***	***31,477,198***	***611,096***	***1.9%***
Other Operating Revenue	262,833	204,167	58,666	28.7%	224,671	38,162	17.0%
Cap & Trade, REC, LCFS and Other Revenue	1,503,800	3,602,000	(2,098,200)	-58.3%	2,083,815	(580,016)	-27.8%
Alameda Point Telephone	11,265	6,250	5,015	80.2%	14,272	(3,007)	-21.1%
Electric Revenue - see 4.C.13 for income statement	**33,866,191**	**36,884,657**	**(3,018,466)**	**-8.2%**	**33,799,956**	**66,235**	**0.2%**
Purchased Power	(9,891,773)	(15,399,028)	5,507,256	-35.8%	(9,962,001)	70,228	-0.7%
Customer Relations	(1,958,966)	(2,418,665)	459,698	-19.0%	(1,685,991)	(272,975)	16.2%
Operations & Maintenance	(3,926,914)	(5,367,745)	1,440,830	-26.8%	(3,841,313)	(85,601)	2.2%
Administration and General	(3,926,688)	(5,238,242)	1,311,554	-25.0%	(3,619,976)	(306,712)	8.5%
Expenses Funded by Special Revenue	(320,490)	(990,583)	670,094	-67.6%	(281,529)	(38,961)	13.8%
Depreciation & Other	(1,347,720)	(1,666,667)	318,947	-19.1%	(1,277,183)	(70,537)	5.5%
Capital Lease Amortization	(133,174)	(133,174)	-	0.0%	(133,174)	-	0.0%
Other Nonoperating Revenue (Expense) - Net	1,349,431	1,038,750	310,681	29.9%	1,249,955	99,477	8.0%
Capital Lease Interest Expense	(30,552)	(30,552)	0.01	0.0%	(34,932)	-	0.0%
Debt Related Charges	(274,397)	(274,543)	146	-0.1%	(326,940)	52,543	-16.1%
PILOT & City Transfer	(2,543,387)	(2,550,287)	6,900	-0.3%	(2,493,533)	(49,854)	2.0%
Alameda Point Telephone	-	(10,417)	10,417	-100.0%	-	-	N/A
Electric Operating & Non-Operating expenses - see 4.C.13 for income statement	**(23,004,630)**	**(33,041,153)**	**10,036,523**	**-30.4%**	**(22,406,619)**	**(598,012)**	**2.7%**
Operating expenses excluding Purchased power, Depreciation	*(10,133,058)*	*(14,015,235)*	*3,882,177*	*-27.7%*	*(9,428,809)*	*(704,249)*	*7.5%*
Electric Net Income (Loss) - see 4.C.13 for income statement	**10,861,561**	**3,843,504**	**7,018,057**	**182.6%**	**11,393,337**	**(531,777)**	**-4.7%**

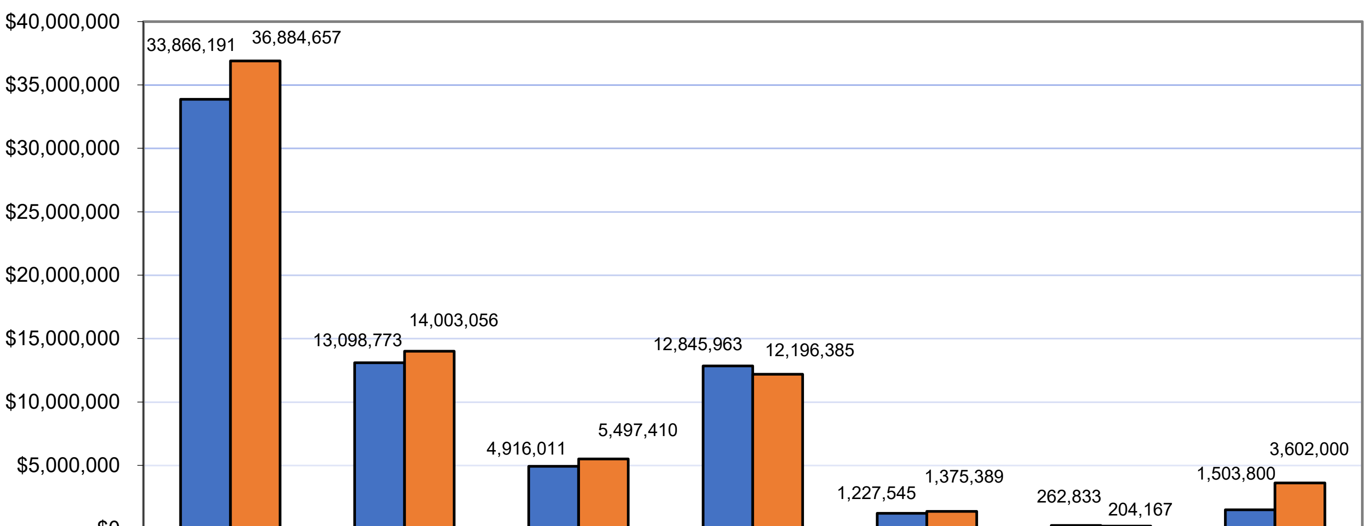
AGENDA ITEM NO: 4.C.5
MEETING DATE 1/12/2026



	KWH total	Residential	General Service (A1)	Demand Metered (A2 &A3)	Municipal
FY2026 Actual	144,616,342	51,956,491	20,646,813	66,545,389	5,467,649
FY2026 Budget	146,538,634	54,823,997	23,073,914	62,575,059	6,065,664

Electric Sales (KWh) through November 2025

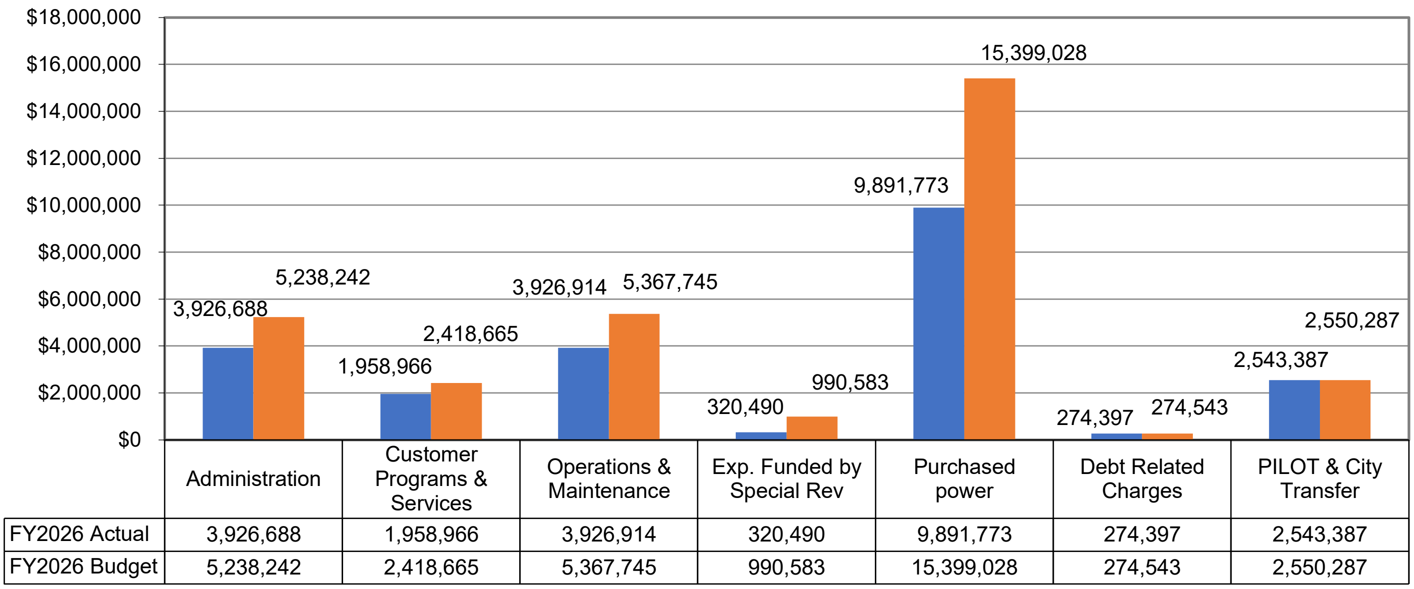
FY2026 Actual FY2026 Budget



	Revenue Total	Residential	General Service (A1)	Demand Metered (A2 &A3)	Municipal	Solar Surcharge & Other Oper. Rev	REC/Cap&Trade Revenue
FY2026 Actual	33,866,191	13,098,773	4,916,011	12,845,963	1,227,545	262,833	1,503,800
FY2026 Budget	36,884,657	14,003,056	5,497,410	12,196,385	1,375,389	204,167	3,602,000

Electric Revenue through November 2025

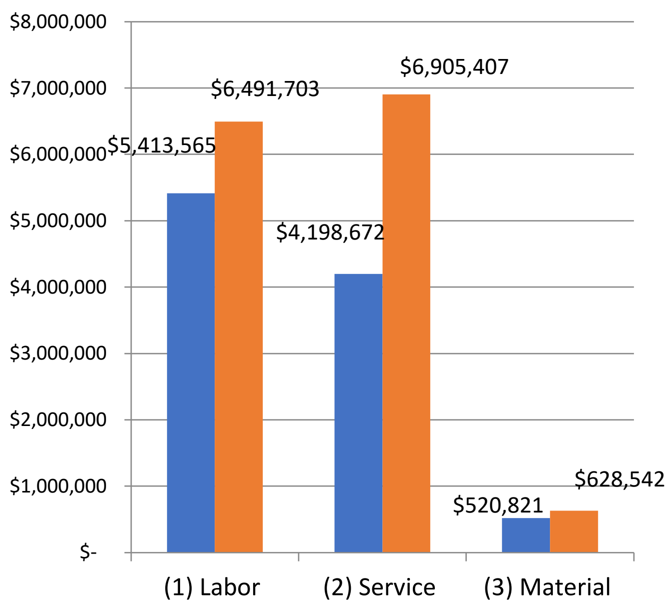
FY2026 Actual FY2026 Budget



	Administration	Customer Programs & Services	Operations & Maintenance	Exp. Funded by Special Rev	Purchased power	Debt Related Charges	PILOT & City Transfer
FY2026 Actual	3,926,688	1,958,966	3,926,914	320,490	9,891,773	274,397	2,543,387
FY2026 Budget	5,238,242	2,418,665	5,367,745	990,583	15,399,028	274,543	2,550,287

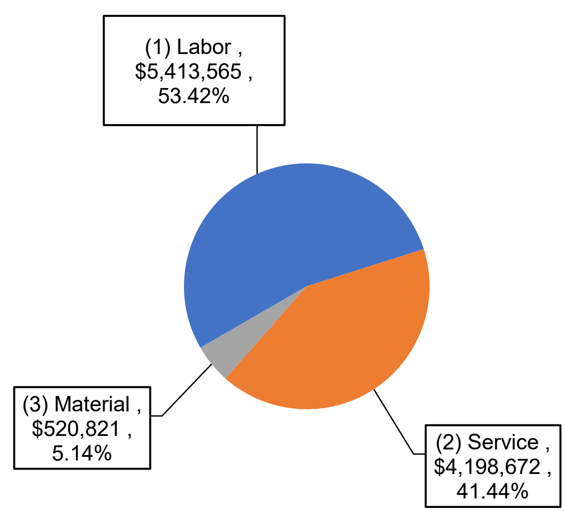
Electric Expense through November 2025

FY2026 Actual FY2026 Budget



YTD Actual YTD Budget

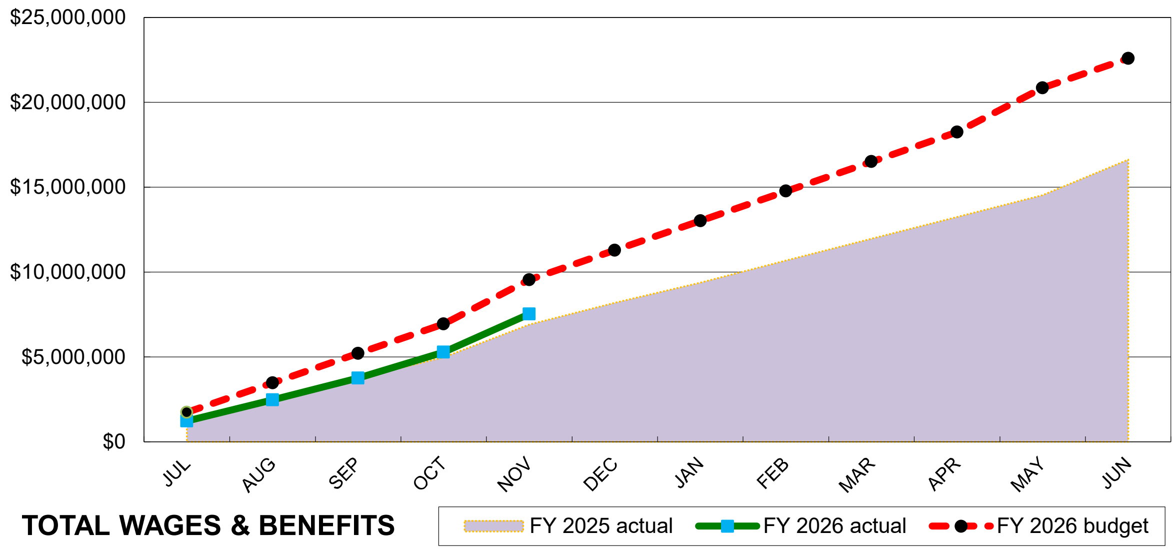
(1) Labor - Wages
(2) Service - Benefits & Other Services Provided by Outside Vendors
(3) Material - Purchased Supplies & Materials



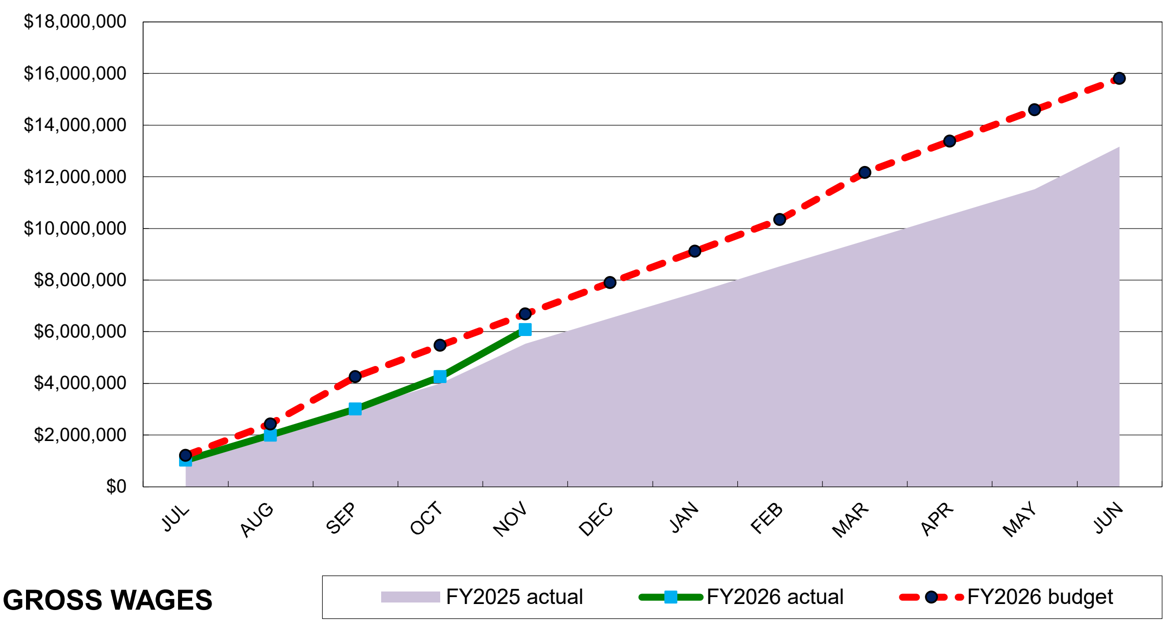
Electric Operating Expenses
Through November 2025
(Purchased Power & Depreciation Excluded)

(1) Labor (2) Service (3) Material

Alameda Municipal Power
Fiscal Year (FY) 2026 Total Wages & Benefits
Through November 2025



TOTAL WAGES & BENEFITS



GROSS WAGES

Budgeted Employees: 94

Actual Employees: 75 + 0 Temp

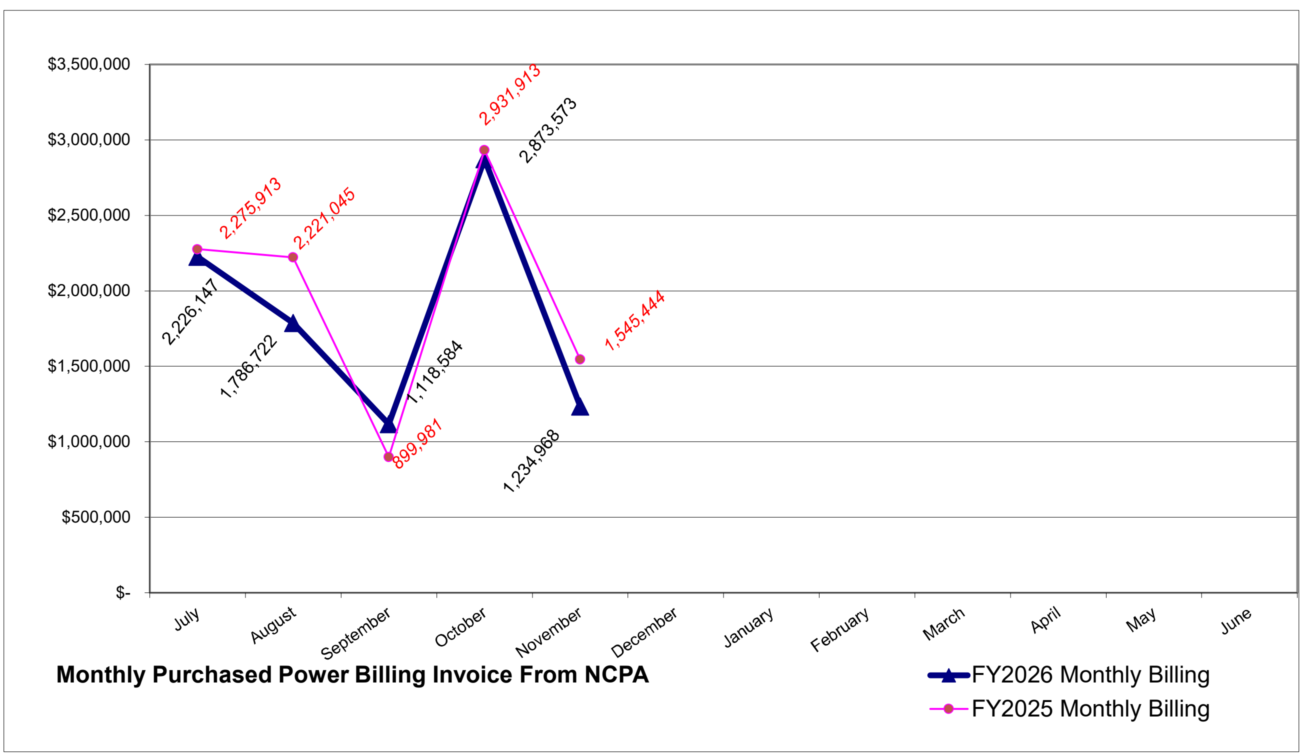
AGENDA ITEM NO: 4.C.8
MEETING DATE 1/12/2026

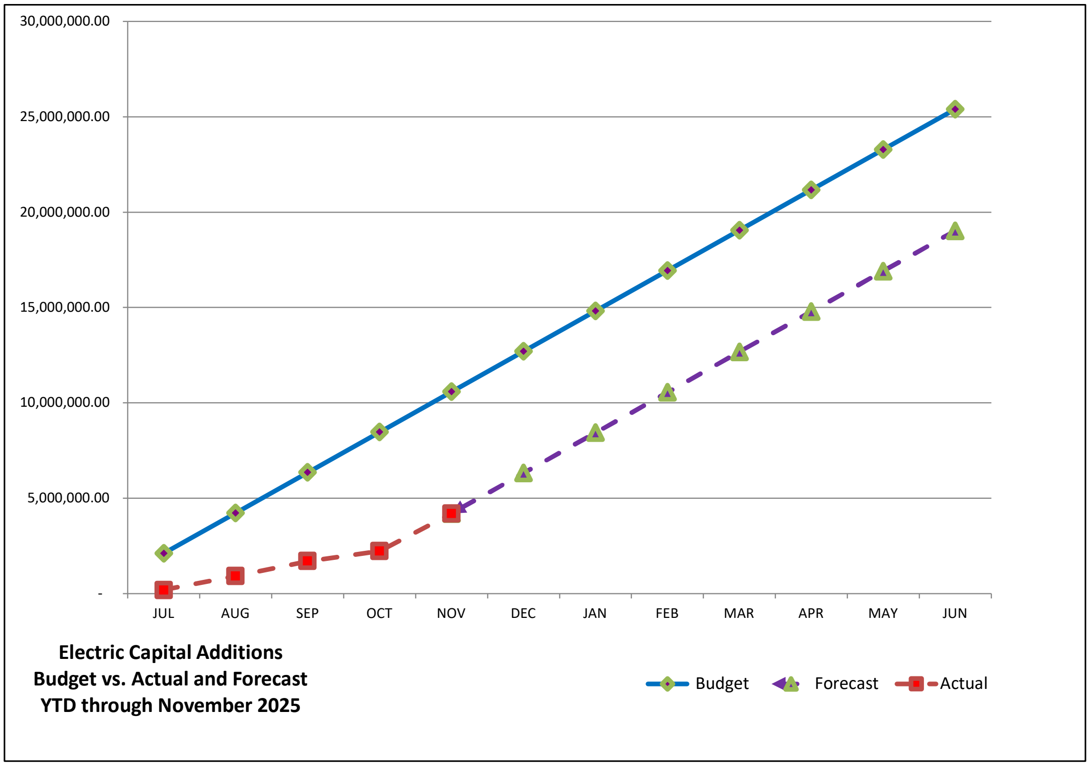
Alameda Municipal Power
Selected Information - Purchased Power Billing From NCPA
for the Month of November 2025

AMP pays purchase power invoices through Northern California Power Agency (NCPA).
Generally, the monthly purchased power cost consists of NCPA's estimated power billing invoice for the current month, and an adjustment for the preceding months.

The monthly gross purchased power billing is listed below:

Power Cost per bill/ Mo.		FY 2026 Monthly	FY 2026 Year-to-Date	FY 2025 Monthly	FY 2025 Year-to-Date
July		2,226,147	2,226,147	2,275,913	2,275,913
August		1,786,722	4,012,869	2,221,045	4,496,958
September		1,118,584	5,131,453	899,981	5,396,939
October		2,873,573	8,005,026	2,931,913	8,328,852
November		1,234,968	9,239,994	1,545,444	9,874,296
December					
January			-		-
February			-		-
March			-		-
April			-		-
May			-		-
June			-		-
Nov./Prior Year	Net Metering Purchase - Solar	22,142	209,672	37,443	210,704
Nov./Prior Year	Payment to NCPA for Energy Efficiency Programs & Other	(32,236)	(106,573)	(22,490)	(112,592)
Nov./Prior Year	Miscellaneous (REC sales/cost)	467,552	548,680	-	-
Prior Year	NCPA Refund for Prior Year Settlement	-	-	-	-
August Power Cost Per GL		1,692,426	9,891,773	1,560,397	9,972,408





	Total Budget	This Month	YTD Actual
Engineering & Operations Capital Projects			
Distribution	1,230,000	116,928	451,731
Distribution - Funded by UUD	8,250,000	1,564,078	3,055,687
New Loads	5,415,000	215,905	715,387
Operations Vehicles	200,000	-	-
Operations Vehicles - Funded by LCFS	0	-	-
Operations	75,000	-	5,033
Substation	8,911,800	152,281	175,950
Transmission	-	-	-
EMGs - Unplanned	-	-	-
Subtotal - E&O Projects	$24,081,800	2,049,192	$4,403,788
Information Systems Capital Projects			
Information Systems Projects	845,000	-	6,608
Subtotal - IS Projects	$845,000	$0	$6,608
Administration Capital Projects			
Administration Projects	-	-	-
Subtotal - Admin Services Projects	$0	$0	$0
Support Services Capital Projects			
Support Services Projects	528,000	-	4,995
Subtotal - Support Services Projects	$528,000	$0	$4,995
Total Capital Projects for FY 2026	**$25,454,800**	**2,049,192**	**$4,415,391**
Inventory - Long Lead Items	**$2,310,000**	**$0**	**$465,653**
Outside Billing Invoiced			
Outside Billing Invoiced - New Loads	(2,364,000)	(76,449)	(681,707)
Outside Billing Invoiced - EMGs	-	-	-
Outside Billing Invoiced FY2026	**($2,364,000)**	**(76,449)**	**($681,707)**
Total Capital Projects + Long Lead Inventory - Invoiced	**$25,400,800**	**1,972,743**	**$4,199,337**

Special Revenue Summary - FY2026
Year To Date through November 2025

Cap & Trade Revenue Reserve - 10 2114	Funding from Cash Receipts	Power Costs	Operating Expenses	Capital Projects	Total Expenditures	Reserve Balance
Reserve Beginning Balance 7/1/2025						1,805,357
Jul-25	-	(166,667)	-	-	(166,667)	1,638,690
Aug-25	-	(166,667)	-	-	(166,667)	1,472,023
Sep-25	481,241	(166,667)	-	-	(166,667)	1,786,597
Oct-25	-	(166,667)	-	-	(166,667)	1,619,930
Nov-25	-	(166,667)	-	-	(166,667)	1,453,263
Dec-25					-	1,453,263
Jan-26					-	1,453,263
Feb-26					-	1,453,263
Mar-26					-	1,453,263
Apr-26					-	1,453,263
May-26					-	1,453,263
Jun-26					-	1,453,263
Total YTD	481,241	(833,335)	-	-	(833,335)	1,453,263

Renewable Energy Credits Revenue Reserve - 10 2113	Funding from Cash Receipts	Power Costs	Operating Expenses	Capital Projects	Total Expenditures	Reserve Balance
Reserve Beginning Balance 7/1/2025						16,095,944
Jul-25	962,388	-	(19,163)	-	(19,163)	17,039,170
Aug-25	-	(227,862)	(13,811)	-	(241,673)	16,797,497
Sep-25	-	(209,382)	(19,135)	-	(228,517)	16,568,980
Oct-25	-	(555,616)	(14,929)	-	(570,545)	15,998,436
Nov-25	467,552	(108,150)	(25,641)	-	(133,791)	16,332,196
Dec-25					-	16,332,196
Jan-26					-	16,332,196
Feb-26					-	16,332,196
Mar-26					-	16,332,196
Apr-26					-	16,332,196
May-26					-	16,332,196
Jun-26					-	16,332,196
Total YTD	1,429,940	(1,101,010)	(92,678)	-	(1,193,688)	16,332,196

Low Carbon Fuel Standard Revenue Reserve - 10 2115	Funding from Cash Receipts	Power Costs	Operating Expenses	Capital Projects	Total Expenditures	Reserve Balance
Reserve Beginning Balance 7/1/2025						1,016,150
Jul-25	-	-	(77,630)	-	(77,630)	938,520
Aug-25	-	-	(15,943)	-	(15,943)	922,577
Sep-25	-	-	(18,573)	-	(18,573)	904,004
Oct-25	-	-	(55,593)	-	(55,593)	848,411
Nov-25	-	-	(60,072)	-	(60,072)	788,339
Dec-25					-	788,339
Jan-26					-	788,339
Feb-26					-	788,339
Mar-26					-	788,339
Apr-26					-	788,339
May-26					-	788,339
Jun-26					-	788,339
Total YTD	-	-	(227,812)	-	(227,812)	788,339
Combined Total	**1,911,181**	**(1,934,345)**	**(320,490)**	**-**	**(2,254,835)**	**18,573,798**

FINANCIAL REPORT DETAIL

AGENDA ITEM NO: 4.C.12
MEETINGDATE: 1/12/2026

Alameda Municipal Power
Financial Notes
For the Month of November 2025

1. **Sales of Electricity:** Electricity sales for the month were 8.2 percent under budget and 1.1 percent higher than the same month last year. Residential sales were 21.2 percent under budget for the month and 2.9 percent higher than in the same month last year. General Service A1 sales were 25.1 percent under budget for the month and 14.1 percent lower than in the same month last year. Demand Metered Services A2 & A3 sales were 17.6 percent over budget for the month and 8.0 percent higher than the same month last year. Municipal and Other Service sales were 21.8 percent under budget for the month and 26.2 percent lower than the same month last year.

   Overall KWh sales were 4.7 percent under budget for the month and 1.0 percent lower than the same month last year. Residential KWh sales were 19.7 percent under budget for the month and 1.9 percent lower than in the same month last year. General Service A1 KWh sales were 23.7 percent under budget for the month and 14.7 percent lower than in the same month last year. Demand Metered Services A2 & A3 KWh sales were 18.9 percent over budget for the month and 6.2 percent higher than the same month last year. Municipal and Other Service KWh sales were 18.8 percent under budget for the month and 26.7 percent lower than the same month last year.

2. **Purchased Power**: Purchased power costs for the month were $2.3M (57.6%) under budget and $157K (10.3%) higher than the same month last year (see 4.C.13 & 4.C.14 Income Statement). The NCPA monthly billing includes estimates for the current month and adjustments for preceding months.

3. **Operating Expenses:** Monthly operating expenses, excluding purchased power and depreciation, were 3.9 percent under budget and 19.2 percent higher than the same month last year. For the year to date, Labor was 16.6 percent under budget, Service was 39.2 percent under budget, and Material was 17.1 percent under budget.

   Non-Operating Revenues and Expenses: Net non-operating revenue was 0.3 percent over budget and 15.8 percent higher than in the same month last year.

Alameda Municipal Power
Comparative Income Statement
For the Period Ending November 2025

	Actual - Current Mo.	Budget - Current Mo.	Over (Under) Budget	% Variance	Actual - YTD	Budget - YTD	Over (Under) Budget	% Variance
Residential (D1 & D2)	9,666,034	12,033,208	(2,367,174)	**-19.7%**	51,956,491	54,823,997	(2,867,506)	**-5.2%**
General Service (A1)	3,319,966	4,349,471	(1,029,505)	**-23.7%**	20,646,813	23,073,914	(2,427,101)	**-10.5%**
Demand Metered (A2 & A3)	13,979,643	11,756,123	2,223,520	**18.9%**	66,545,389	62,575,059	3,970,330	**6.3%**
Municipal & Other (M1, M2, M3, OL, CT&VG)	924,349	1,138,729	(214,380)	**-18.8%**	5,467,649	6,065,664	(598,015)	**-9.9%**
Electric Sales (KWH):	**27,889,992**	**29,277,531**	**(1,387,539)**	**-4.7%**	**144,616,342**	**146,538,634**	**(1,922,292)**	**-1.3%**
Commercial & Industrial	***17,299,609***	***16,105,595***	***1,194,014***	***7.4%***	***87,192,202***	***85,648,973***	***1,543,229***	***1.8%***
Excess Solar Generation	***(175,125)***	-	***(175,125)***		***(1,606,281)***	-		
Operating Revenues								
Sale of Electricity	6,010,522	6,548,924	(538,402)	-8.2%	32,088,294	33,072,240	(983,946)	-3.0%
Electric Other Operating Sales	32,782	40,833	(8,052)	-19.7%	262,833	204,167	58,666	28.7%
Cap & Trade Net Revenues	473,879	180,400	293,479	162.7%	955,120	902,000	53,120	5.9%
REC Revenue	467,552	506,667	(39,115)	-7.7%	548,680	2,533,333	(1,984,653)	-78.3%
Low Carbon Fuel Standard Credit Sales	-	33,333	(33,333)	-100.0%	-	166,667	(166,667)	-100.0%
Telephone Revenue	1,140	1,250	(110)	-8.8%	11,265	6,250	5,015	80.2%
Total Operating Revenue	***6,985,875***	***7,311,407***	***(325,532)***	***-4.5%***	***33,866,191***	***36,884,657***	***(3,018,466)***	***-8.2%***
Operating Expense								
Purchased Power	1,692,426	3,993,492	(2,301,066)	-57.6%	9,891,773	15,399,028	(5,507,256)	-35.8%
Energy Efficiency	15,556	26,983	(11,427)	-42.3%	56,163	134,917	(78,754)	-58.4%
Cust Assit, Solar rebate & other	27,171	26,667	504	1.9%	141,810	133,333	8,477	6.4%
Alameda Point Telephone	-	2,083	(2,083)	-100.0%	-	10,417	(10,417)	-100.0%
Operations & Maintenance	1,212,148	1,073,549	138,599	12.9%	3,926,914	5,367,745	(1,440,830)	-26.8%
Customer Service	292,197	347,275	(55,078)	-15.9%	1,373,023	1,736,373	(363,350)	-20.9%
Administration and General	989,438	1,047,648	(58,210)	-5.6%	3,926,688	5,238,242	(1,311,554)	-25.0%
Depreciation & Amortization	269,273	333,333	(64,060)	-19.2%	1,347,720	1,666,667	(318,947)	-19.1%
Capital Lease Amortization	26,635	26,635	-	0.0%	133,174	133,174	-	0.0%
Customer Relations	72,732	82,808	(10,076)	-12.2%	387,970	414,042	(26,072)	-6.3%
Expenses Funded by Special Revenue	85,714	198,117	(112,403)	-56.7%	320,490	990,583	(670,094)	-67.6%
Total Operating Expense	***4,683,290***	***7,158,590***	***(2,475,300)***	***-34.6%***	***21,505,725***	***31,224,521***	***(9,718,796)***	***-31.1%***
Operating Income (Loss)	**2,302,585**	**152,817**	**2,149,768**	**1406.8%**	**12,360,466**	**5,660,136**	**6,700,330**	**118.4%**
Nonoperating Income (Expense)								
Return on Investments	72,018	187,500	(115,482)	-61.6%	1,084,035	937,500	146,535	15.6%
Return on Restricted Investments	11,932	-	11,932	100.0%	60,701	-	60,701	N/A
Capital Lease Interest Expense	(4,934)	(4,934)	-	0.0%	(30,552)	(30,552)	0	0.0%
Debt Related Charges	(54,879)	(54,909)	29	-0.1%	(274,397)	(274,543)	146	-0.1%
Net Nonoperating Income (Expense)	20,317	20,250	67	0.3%	204,695	101,250	103,445	102.2%
Payment in Lieu of Taxes	(140,417)	(141,797)	1,380	-1.0%	(702,083)	(708,983)	6,900	-1.0%
Total Nonoperating Income	***(95,963)***	***6,111***	***(102,074)***	***-1670.4%***	***342,399***	***24,672***	***317,727***	***1287.8%***
Income Before Transfer to the City	**2,206,622**	**158,928**	**2,047,694**	**1288.4%**	**12,702,865**	**5,684,808**	**7,018,057**	**123.5%**
Transfer to the City	(460,326)	(460,326)	-	0.0%	(1,841,304)	(1,841,304)	-	0.0%
Net Income (Loss)	**1,746,295**	**(301,398)**	**2,047,694**	**-679.4%**	**10,861,561**	**3,843,504**	**7,018,057**	**182.6%**

Alameda Municipal Power
Comparative Income Statement
For the Period Ending November 2025

	Actual - Current Mo.	Prior Year - Current Mo.	Over (Under)	% Variance	Actual - YTD	Prior Year - YTD	Over (Under)	% Variance
Residential (D1 & D2)	9,666,034	9,850,851	(184,817)	**-1.9%**	51,956,491	52,789,667	(833,176)	**-1.6%**
General Service (A1)	3,319,966	3,891,300	(571,334)	**-14.7%**	20,646,813	22,843,594	(2,196,781)	**-9.6%**
Demand Metered (A2 & A3)	13,979,643	13,159,029	820,614	**6.2%**	66,545,389	65,639,752	905,637	**1.4%**
Municipal & Other (M1, M2, M3, OL, CT&VG)	924,349	1,261,015	(336,666)	**-26.7%**	5,467,649	5,982,817	(515,168)	**-8.6%**
Electric Sales (KWH):	**27,889,992**	**28,162,195**	**(272,203)**	-1.0%	**144,616,342**	**147,255,830**	**(2,639,488)**	-1.8%
Commercial & Industrial	***17,299,609***	***17,050,329***	***249,280***	***1.5%***	***87,192,202***	***88,483,346***	***(1,291,144)***	***-1.5%***
Excess Solar Generation	***(175,125)***	***(155,117)***	***(20,008)***	***12.9%***	***(1,606,281)***	***(1,825,008)***	***218,727***	***-12.0%***
Operating Revenues								
Sale of Electricity	6,010,522	5,944,062	66,460	1.1%	32,088,294	31,477,198	611,096	1.9%
Electric Other Operating Sales	32,782	39,155	(6,373)	-16.3%	262,833	224,671	38,162	17.0%
Cap & Trade Net Revenues	473,879	558,744	(84,866)	-15.2%	955,120	1,088,247	(133,127)	-12.2%
REC Revenue	467,552	-	467,552		548,680	-	548,680	N/A
Low Carbon Fuel Standard Credit Sales	-	-	0		-	995,569	(995,569)	-100.0%
Telephone Revenue	1,140	2,824	(1,684)	-59.6%	11,265	14,272	(3,007)	-21.1%
Total Operating Revenue	***6,985,875***	***6,544,785***	***441,090***	***6.7%***	***33,866,191***	***33,799,956***	***66,235***	***0.2%***
Operating Expense								
Purchased Power	1,692,426	1,535,038	157,388	10.3%	9,891,773	9,962,001	(70,228)	-0.7%
Energy Efficiency	15,556	34,131	(18,575)	-54.4%	56,163	128,003	(71,840)	-56.1%
Cust Assit, Solar rebate & other	27,171	23,113	4,058	17.6%	141,810	123,411	18,399	14.9%
Alameda Point Telephone	-	-	-		-	-	-	N/A
Operations & Maintenance	1,212,148	947,743	264,404	27.9%	3,926,914	3,841,313	85,601	2.2%
Customer Service	292,197	288,820	3,377	1.2%	1,373,023	1,207,002	166,021	13.8%
Administration and General	989,438	857,441	131,998	15.4%	3,926,688	3,619,976	306,712	8.5%
Depreciation Expense	269,273	255,579	13,694	5.4%	1,347,720	1,277,183	70,537	5.5%
Capital Lease Amortization Expense	26,635	26,635	-	0.0%	133,174	133,174	-	0.0%
Customer Relations	72,732	58,229	14,503	24.9%	387,970	227,575	160,395	70.5%
Expenses Funded by Special Revenue	85,714	51,307	34,407	67.1%	320,490	281,529	38,961	13.8%
Total Operating Expense	***4,683,290***	***4,078,036***	***605,254***	***-14.8%***	***21,505,725***	***20,801,168***	***704,558***	***-3.4%***
Operating Income (Loss)	**2,302,585**	**2,466,749**	**(164,164)**	**-6.7%**	**12,360,466**	**12,998,788**	**(638,323)**	**-4.9%**
Nonoperating Income (Expense)								
Return on Investments	72,018	52,138	19,881	38.1%	1,084,035	1,105,685	(21,650)	-2.0%
Return on Restricted Investments	11,932	13,934	(2,002)	-14.4%	60,701	73,249	(12,548)	-17.1%
Capital Lease Interest	(4,934)	(5,674)	740	-13.0%	(30,552)	(34,932)	4,380	-12.5%
Debt Related Charges	(54,879)	(65,388)	10,509	-16.1%	(274,397)	(326,940)	52,543	-16.1%
Net Nonoperating Income (Expense)	20,317	17,538	2,779	15.8%	204,695	71,021	133,674	188.2%
Payment in Lieu of Taxes	(140,417)	(137,667)	(2,750)	-100.0%	(702,083)	(688,333)	(13,750)	2.0%
Total Nonoperating Income	***(95,963)***	***(125,119)***	***29,156***	***-23.3%***	***342,399***	***199,749***	***142,650***	***71.4%***
Income Before Transfer to the City	**2,206,622**	**2,341,630**	**(135,008)**	**-5.8%**	**12,702,865**	**13,198,537**	**(495,673)**	**-3.8%**
Transfer to the City	(460,326)	(451,300)	(9,026)	2.0%	(1,841,304)	(1,805,200)	(36,104)	2.0%
Net Income (Loss)	**1,746,295**	**1,890,330**	**(144,035)**	**-7.6%**	**10,861,561**	**11,393,337**	**(531,777)**	**-4.7%**

AGENDA ITEM NO: 4.C.15
MEETING DATE 1/12/2026

Consolidated Balance Sheet

	As of 11/30/2025	As of 11/30/2024	Net Change	% Change
ASSETS				
Utility Plant	123,657,722	121,758,708	1,899,015	1.6%
Construction in Progress	17,646,895	10,900,239	6,746,656	61.9%
Accumulated Depreciation	(97,761,937)	(96,435,500)	(1,326,437)	1.4%
Capital Lease-Building	3,142,914	3,142,914	0	0.0%
Accumulated Capital Lease Amortization	(1,411,648)	(1,092,029)	(319,618)	29.3%
	45,273,947	**38,274,332**	**6,999,615**	**18.3%**
Restricted Investments				
2010 A&B Installment Fund	1,148,933	1,153,228	(4,295)	-0.4%
2010 A&B Reserve Fund	3,146,147	3,028,469	117,678	3.9%
Restricted Investments	**4,295,081**	**4,181,697**	**113,383**	**2.7%**
Investments Reserved - Special Purpose				
Insurance Reserve	1,200,000	1,200,000	0	0.0%
Underground Cons. Reserve	9,209,900	14,502,144	(5,292,244)	-36.5%
REC Net Revenue Reserve	16,332,196	16,048,653	283,543	1.8%
Cap & Trade Net Rev Reserve	1,453,263	1,490,680	(37,416)	-2.5%
Low Carbon Fuel St. Rev Reserve	788,339	1,372,705	(584,366)	-42.6%
Investments Reserved - Special Purpose	**28,983,698**	**34,614,182**	**(5,630,483)**	**-16.3%**
Non Current Assets				
NCPA Projects & Reserves	8,747,196	7,191,054	1,556,142	21.6%
Electric Deposits	40,000	40,000	0	0.0%
Debt Issue Costs (Net)	166,203	227,854	(61,651)	-27.1%
Deferred Outflows - Pension	4,912,184	7,158,222	(2,246,038)	-31.4%
Deferred Outflows - OPEB	123,227	84,017	39,210	46.7%
Telecom Deposits	10,813	2,062	8,751	424.4%
Non-Current Assets	**13,999,624**	**14,703,209**	**(703,585)**	**-4.8%**
Current Assets				
Cash & Cash Equivalents	96,088,038	83,080,759	13,007,279	15.7%
Interest Receivable	45,517	18,175	27,343	150.4%
Accounts Receivable	9,652,236	10,523,884	(871,648)	-8.3%
Materials and Supplies	8,028,698	7,951,659	77,039	1.0%
Prepaid Power Costs & Others	0	0	0	0.0%
Current Assets	**113,814,489**	**101,574,476**	**12,240,013**	**12.1%**
Total Assets	**206,366,839**	**193,347,896**	**13,018,944**	**6.7%**

AGENDA ITEM NO: 4.C.16
MEETING DATE 1/12/2026

CAPITALIZATION AND LIABILITIES

Capitalization:				
Earned Surplus:				
Unappropriated	46,178,151	33,813,764	12,364,387	36.6%
Appropriated Earnings	30,832,233	36,462,716	(5,630,483)	-15.4%
Current Net Earnings and Expense	10,861,561	11,393,337	(531,777)	-4.7%
Earned Surplus	**87,871,944**	**81,669,818**	**6,202,127**	**7.6%**
Equity in NCPA Joint Venture	**8,747,196**	**7,191,055**	**1,556,141**	**21.6%**
Long Term Liabilities				
Long Term Debts	37,457,098	40,980,725	(3,523,627)	-8.6%
Capital Lease Payables-Building	1,948,122	2,245,779	(297,657)	-13.3%
Deferred Inflows - Pension	944,688	430,856	513,832	119.3%
Long Term Liabilities	**40,349,908**	**43,657,360**	**(3,307,452)**	**-7.6%**
Current Liabilities:				
Accounts Payable and Accrued Payroll	1,425,300	2,845,256	(1,419,956)	-49.9%
Interest Payable	248,708	301,252	(52,543)	-17.4%
Purchase Power Balancing Account	57,926,500	47,888,828	10,037,672	21.0%
Deposits	7,511,374	7,686,770	(175,396)	-2.3%
Taxes Payable	409,909	487,400	(77,490)	-15.9%
Other Accrued Liabilities	1,876,000	1,620,158	255,842	15.8%
Current Liabilities	**69,397,791**	**60,829,663**	**8,568,128**	**14.1%**
Total Capitalization and Liabilities	**206,366,839**	**193,347,896**	**13,018,944**	**6.7%**

Alameda Municipal Power
Electric & Alameda Point Phone Services
Statement of Cash Flows
For the Month of November 2025

	Current Month		Year to Date	
Net Cash Flows from Operating Activities				
Net Income (Loss) - Electric	1,746,295		10,861,561	
Net Income (Loss) - Alameda Point Phone			-	
- Depreciation & Amortization expense	295,908		1,480,894	
- Debt Cost Amortization	5,138		25,688	
- Balancing Account Year-end Adjustment			-	
- (Increase) Decrease in Lease Deposit			-	
- (Increase) Decrease in Accounts Receivable	(231,798)		(1,093,760)	
- (Increase) Decrease in Interest Receivable	(17,333)		744,629	
- (Increase) Decrease in Material & Supplies Inventory	113,055		302,065	
- (Increase) Decrease in Prepaids	-		-	
- Increase (Decrease) in Accounts Payable	976,335		(3,588,869)	
- Increase (Decrease) in Interest Payable	49,742		(112,794)	
- Increase (Decrease) in Customer Deposits	(70,373)		(86,982)	
- Increase (Decrease) in Taxes Payable	(67,736)		410,338	
- Increase (Decrease) in Other Accrued Liabilities	(4,691)		(6,147)	
- Increase (Decrease) in Pension-related Liabilities			-	
Net cash provided (used) by operating activities		2,794,543		8,936,624
Cash Flows From Investing Activities				
(Increase) Decrease in Utility Plant	-		-	
(Increase) Decrease in Construction Work in Progress	(1,972,743)		(3,733,684)	
2010A&B Bond Fund Debt Service Trustee A/C	(220,422)		1,194,027	
2010A&B Common Reserve Account Interest Income	(9,571)		(48,530)	
Sale Proceed of Obsolete Assets	-		-	
(Increase) Decrease in NCPA - GOR Value	-		-	
(Increase) Decrease in NCPA - Projects Value	-		-	
(Increase) Decrease in Northern California Power Agency Various Deposits	-		-	
Net cash provided (used) by investing activities		(2,202,736)		(2,588,187)
Cash Flows From Financing Activites				
2010A Bond Issuance Proceed	-		-	
2010B Bond Principal Payment	-		(1,935,000)	
2010A&B Bond Issuance Cost	-		-	
Payment for Capital Lease Payable	(25,444)		(151,715)	
Net cash provided (used) by financing activities		(25,444)		(2,086,715)
Net Increase (Decrease) in Cash		566,363		4,261,721
Appropriation for Reserves				
(Increase) Decrease in Underground Fund Reserve		1,431,405		2,059,273
(Increase) Decrease in Solar Photovoltaic Rebate Reserve		-		-
(Increase) Decrease in Renewable Energy Credits Net Revenue Reserve		(333,761)		(236,252)
(Increase) Decrease in Cap&Trade Net Revenue Reserve		166,667		352,094
(Increase) Decrease in Low Carbon Fuel St Rev Reserve		60,072		227,812
- Subtotal (Increase) Decrease in in Reserves		1,324,384		2,402,927
Total Increase (Decrease) in Cash		1,890,747		6,664,648
Cash - 6/30/2025				89,423,390
Cash - 10/31/2025		94,197,291		
Cash - 11/30/2025		96,088,038		96,088,038
Additional Information				
Reserves for Special Purposes at 6/30/2025			31,386,625	
Reserves for Special Purposes at 10/31/2025	30,308,083			
Net Increase (Decrease) for the period	(1,324,384)		(2,402,927)	
Reserves for Special Purposes at 11/30/2025	28,983,698		28,983,698	

Alameda Municipal Power
Utility Plant Detail--Electric
For the Month of November, 2025

		General Ledger	Utility Plant	General Ledger	Accumulated Depreciation	Net Utility Plant
Transmission						
Land & Land Rights	350.101	2501	$ 69,333		$ -	$ 69,333
Structures & Improvements - West Crossing	351.101	2522	74,662	2822	72,552	2,110
Structures & Improvements - East Crossing	352.101	2522	68,948	2822	67,434	1,514
Transformer Towers & Fixtures	354.101	2522	461,652	2822	461,652	-
Transformer Poles & Fixtures	355.101	2522	924,266	2822	778,567	145,699
Overhead Conductors & Devices	356.101	2522	842,526	2822	724,144	118,381
Underground Conduits	357.101	2522	366,075	2822	361,569	4,506
Underground Conductors & Devices	358.101	2522	1,359,176	2822	1,353,924	5,252
Total Transmission			$ 4,166,639		$ 3,819,843	$ 346,796
Distribution						
Land & Land Rights - Grand St. Station	360.101	2501	$ 36,867		$ -	$ 36,867
Land & Land Rights - Jenny Station (50 Years)	360.101	2501	66,500		-	66,500
Structures & Improvements -Grand St.Cartwright & Jenny Substations	361.101	2511	2,498,155	2811	1,738,372	759,784
Station Equipment - Grand St. Station	362.101	2521	946,631	2821	520,568	426,064
Station Equipment - Cartwright Station	362.101	2521	4,095,485	2821	1,590,165	2,505,320
Station Equipment - Jenny Station	362.101	2521	4,066,346	2821	2,369,064	1,697,282
Station Equipment - NCPA Station	362.101	2521	384,502	2821	32,042	352,460
Storage Battery - Jenny Station	363.501	2521	51,194	2821	51,194	-
Poles Towers & Fixtures	364.101	2521	10,546,972	2821	8,565,228	1,981,744
Overhead Conductors & Devices	365.101	2521	10,114,516	2821	8,651,258	1,463,259
Underground Conduits	366.101	2521	13,797,170	2821	11,669,169	2,128,001
Underground Conductors & Devices	367.101	2521	23,720,726	2821	20,274,588	3,446,137
Line Transformers	368.101	2521	9,475,873	2821	7,409,783	2,066,090
Services	369.101	2521	4,137,156	2821	3,965,038	172,118
Meters	370.101	2521	9,429,893	2821	6,420,365	3,009,527
Total Distribution			$ 93,367,987		$ 73,256,834	$ 20,111,153
General Plant						
Land & Land Rights - Grand St. Station	389.101	2501	$ 47,444		$ -	$ 47,444
Structures & Improvements	390.101	2511	5,669,913	2811	3,797,424	1,872,489
Office Mechanical Equipment	391.101	2551	1,268,846	2851	1,239,904	28,942
Office Furniture & Other Equipment	391.201	2571	977,905	2871	817,122	160,783
Computer Equipment & Software	391.301	2561	3,760,302	2861	3,456,998	303,304
Office Equipment-System Software-Cayenta	391.306	2591	981,720	2891	839,817	141,903
Dispatch Center Equipment	391.401	2551	624,866	2851	360,260	264,606
Construction Vehicles	392.106	2581	3,647,765	2881	1,539,943	2,107,823
Electric Transportation Vehicles	392.107	2581	189,156	2881	169,523	19,633
Electric Construction Vehicles	392.108	2581	383,470	2881	195,423	188,047
Stores Equipment	393.101	2551	128,117	2851	117,458	10,659
Shop & Garage Equipment	394.101	2551	25,713	2851	25,713	-
Tools & Work Equipment	394.201	2551	800,752	2851	800,752	-
Communication Equipment	397.101	2551	6,861,449	2851	6,738,404	123,045
Miscellaneous Equipment	398.101	2551	755,679	2851	586,520	169,159
Total General Plant			$ 26,123,096		$ 20,685,260	$ 5,437,836
Subtotal			$ 123,657,722		$ 97,761,937	$ 25,895,785
Capital Leases						
1835 Oak Warehouse Lease		2595	$ 3,142,914	2895	$ 1,411,648	$ 1,731,266
Construction Work In Progress (CWIP)		2701 2704	$ 17,646,895		$ -	$ 17,646,895
Grand Total			$ 144,447,532		$ 99,173,585	$ 45,273,947

Alameda Municipal Power
Calculation of Non-Power Costs for Balancing Account
Fiscal Year (FY) 2026 Year To Date (YTD) through November 2025

	FY 2025 Annual Budget	FY 2026 Annual Budget	FY 2026 Year-to-Date Budget	FY 2026 Year-to-Date Actual
Revenue				
Sale of Electricity - see Income Statement (4.C.13)	**76,399,290**	**79,603,249**	**33,072,240**	**32,088,294**
Other Revenue				
Other Electric Operating Sales	445,000	490,000	204,167	262,833
Cap&Trade Sales Income & Low Carbon Fuel Standard Credit Sale	2,871,000	2,564,800	902,000	955,120
Renewable Eenergy Credits (REC) Sales Income	-	6,080,000	2,533,333	548,680
Interest Income	1,250,000	2,250,000	937,500	1,144,737
Less Restricted Interest Income for Trustee Account	-	-	-	(60,701)
Non-Operating Income/Deduction Net	288,000	243,000	101,250	204,695
Reserves Reduction - Release Reserves funds for designated usages	14,654,000	13,021,000	5,425,417	4,977,469
	19,508,000	**24,648,800**	**10,103,667**	**8,032,832**
Retainments: Underground Utility District Reserve Funding	(1,528,000)	(1,592,000)	(663,333)	(663,360)
Retainments: Solar Surcharge	-	-	-	-
Retainments: Cap&Trade and REC Sales Revenue	(2,471,000)	(8,244,800)	(3,435,333)	(1,911,181)
Retainments: Low Carbon Fuel Standard	(400,000)	(400,000)	(166,667)	-
	(4,399,000)	**(10,236,800)**	**(4,265,333)**	**(2,574,541)**
Adjusted Net Revenue	**91,508,290**	**94,015,249**	**38,910,573**	**37,546,585**
Purchased Power	**(35,478,671)**	**(36,796,667)**	**(15,399,028)**	**(9,891,773)**
Expense Items Included In Non-Power Costs				
Total Operating Expenses - see Income Statement (4.C.13)	(68,445,879)	(74,458,231)	(31,224,521)	(21,505,725)
Remove Purchased Power included in Total Operating Expenses	35,478,671	36,796,667	15,399,028	9,891,773
Non-Power Operating Expenses	**(32,967,208)**	**(37,661,564)**	**(15,825,493)**	**(11,613,952)**
Remove Depreciation	4,000,000	4,000,000	1,666,667	1,347,720
Non-Power Operating Expenses Excluding Depreciation	(28,967,208)	(33,661,564)	(14,158,826)	(10,266,232)
Debt Related Charges interest	(785,006)	(658,902)	(274,543)	(274,397)
Less Debt Cost Amortization	62,000	62,000	25,833	25,688
Oak Building Capital Lease-Liability	(287,969)	(307,545)	(126,271)	(151,715)
Oak Building Capital Lease Interest Expense	(67,718)	(58,812)	(30,552)	(30,552)
Payment In Lieu Of Taxes /Return On Investment	(1,652,000)	(1,701,560)	(708,983)	(702,083)
Non-Operating Revenue & Expenses	**(2,730,693)**	**(2,664,819)**	**(1,114,516)**	**(1,133,060)**
Capital Projects (see 4.C.9)	(19,220,200)	(25,454,800)	(10,606,167)	(4,415,391)
Inventory Purchases-Long Lead Items advance purchase	(2,310,000)	(2,310,000)	(962,500)	(465,653)
Total Non-Power Costs	**(53,228,101)**	**(64,091,183)**	**(26,842,009)**	**(16,280,335)**
Recap of Income and Expenses				
Sale of Electricity	**76,399,290**	**79,603,249**	**33,072,240**	**32,088,294**
Other Revenue Sources	**19,508,000**	**24,648,800**	**10,103,667**	**8,032,832**
Retainments	**(4,399,000)**	**(10,236,800)**	**(4,265,333)**	**(2,574,541)**
Purchased Power Costs	**(35,478,671)**	**(36,796,667)**	**(15,399,028)**	**(9,891,773)**
Total Non-Power Costs Excluding City Transfer	**(53,228,101)**	**(64,091,183)**	**(26,842,009)**	**(16,280,335)**
Transfer to City of Alameda General Fund	**(4,513,460)**	**(4,603,260)**	**(1,841,304)**	**(1,841,304)**
Over (Under) Collection	**(1,711,942)**	**(11,475,861)**	**(5,171,767)**	**9,533,173**

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

AGENDA ITEM NO.: 4.D.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: AR2026-38

To: Honorable Public Utilities Board

Submitted by: /S/
Teri Dean Alderson
AGM -Administration

From: Charlene Leu
Financial Analyst

Approved by: /S/
Tim Haines
General Manager

Subject: Treasurer's Report for the Month Ending November 2025

RECOMMENDATION

For information only, no action is recommended.

BACKGROUND

This report is submitted in compliance with Alameda Municipal Power's (AMP) policy and the State of California Government Code Sections 53607 and 53646(b).

DISCUSSION

Funds have been managed and invested in compliance with the Public Utilities Board's Resolution No. 5214. AMP's expenditure requirements for the next six months are covered by anticipated revenues and the liquidity of current investments.

Investments
The total book value of AMP's investment portfolio is $110,731,193. The current market value of the portfolio totals $110,998,698. Investments are held to maturity or may be sold when prices yield a gain on the sale. The overall portfolio has a weighted average interest rate of 3.916 percent.

Interest Rates
During the period, the rate on 3-Years US Treasury Bills decreased 9 basis points from 3.581 percent on October 31, 2025 to 3.493 percent on November 30, 2025. The rate on the Secured Overnight Financial Rate (SOFR) decreased 10 basis points from 4.22 percent on October 31, 2025 and 4.12 percent on November 30, 2025. The rate on Local Agency Investment Fund (LAIF) decreased 5 basis points from 4.15 percent on October 31, 2025 to 4.096 percent on November 30, 2025.

BUDGET CONSIDERATION/FINANCIAL IMPACT

None

EXHIBITS

A. Investment Portfolio Summary and Detail
B. Supplemental Schedule - Sources of Investments & Investment Portfolio

Alameda Municipal Power
INVESTMENT PORTFOLIO SUMMARY
November 30, 2025

	Current Market Value	Book Value	Unrealized Gain (Loss)	Percent of Total	Average Return
Local Agency Investment Fund	$72,887,002	$72,887,002	$0	65.82%	4.096%
U.S. Government Agencies	19,963,623	19,748,906	214,718	17.83%	3.708%
U.S. Government Bonds	0	0	0	0.00%	0.000%
Cash & Money Market	82,009	82,009	0	0.07%	0.010%
Municipal Bonds	7,789,014	7,664,779	124,235	6.92%	3.846%
Corporate Fixed Income	6,359,120	6,426,988	(67,868)	5.80%	2.813%
Certificates of Deposit(s)	3,917,929	3,921,509	(3,580)	3.54%	3.637%
Total Investment Portfolio and Weighted Average Return	$110,998,698	$110,731,193	$267,505	100.00%	3.916%

Fiscal Year (FY) 2026 Budgeted Interest Income	$2,250,000
FY2026 Year-to-date Interest Income Estimated	$1,146,163
Percent of Interest Received To Date	50.9%

	Actual	**Budgeted**
FY 2025 Interest Income	$3,866,039	$1,250,000
FY 2024 Interest Income	$3,482,735	$1,125,000
FY 2023 Interest Income	$2,181,183	$1,125,000
FY 2022 Interest Income	$913,447	$1,125,000
FY 2021 Interest Income	$986,505	$1,225,000

DETAIL OF INVESTMENT PORTFOLIO
November 30, 2025

Alameda Municipal Power

Investment CUSIP	Investment Description	Custodian / S&P Rating	Par Value	Coupon Rate	Current Market Value	Date of Investment	Date of Maturity	ys tu	% of Portfolio	Yield to Maturity	Call Date	Book Value Purchase Price
	Local Agency Investment Fund (LAIF)	LAIF	72,887,002		72,887,002.42	11/01/25	11/30/25	30	65.66%	4.096%		72,887,002.42
	Cash & Money Market Funds		$ 82,009		82,008.61	11/01/25	11/30/25	30	0.07%	0.010%		82,008.61
		Subtotal	$82,009		82,008.61	Subtotal	n					82,008.61
	U.S. Government Treasuries & Agencies											
3133EMPU0	FEDERAL FARM CR BKS 0.5% 2/4/2026	AA+	500,000	0.500%	496,875.00	06/13/25	02/04/26		0.45%	0.500%		488,823.16
3133EMT36	FEDERAL FARM CR BKS 0.87% 4/15/2026	AA+	400,000	0.870%	395,480.00	12/13/24	04/15/26		0.36%	4.098%		383,259.59
3133ETL39	FEDERAL FARM CR BKS 3.87% 10/23/2028	AA+	400,000	3.870%	399,732.00	11/06/25	10/23/28		0.36%	3.870%	4/23/26	400,000.00
3133ER5H0	FEDERAL FARM CR BKS 4.7% 3/5/2029	AA+	300,000	4.700%	300,558.00	11/21/25	03/05/29		0.27%	4.507%	3/5/26	301,761.87
3133ER5H0	FEDERAL FARM CR BKS 4.7% 3/5/2029	AA+	500,000	4.700%	500,930.00	11/26/25	03/05/29		0.45%	4.476%	3/5/26	503,385.00
3133ENJ35	FEDERAL FARM CR BKS 3.32% 2/25/2026	AA+	150,000	3.320%	149,773.50	12/23/24	02/25/26		0.13%	4.126%		148,622.55
3134GWBN5	FEDERAL HOME LN MTG CORP 0.8% 7/30/2026		400,000	0.800%	392,380.00	12/13/24	07/30/26		0.35%	4.120%	01/30/26	379,158.52
3134GXXE9	Federal Home Ln Mtg Corp 3.15%, 12/29/25	AA+	400,000	3.150%	399,744.00	06/29/22	12/29/25		0.36%	3.377%		397,000.00
3134HA6A6	FEDERAL HOME LN MTG CORP 4.55% 2/11/2028	AA+	500,000	4.550%	499,875.00	11/26/25	02/11/28		0.45%	4.270%	2/11/26	502,888.35
3130AKXX9	FEDERAL HOME LOAN BANKS 0.5% 2/25/2026	AA+	500,000	0.500%	496,015.00	07/03/25	02/25/26		0.45%	4.326%		488,936.09
3130AKJW7	FEDERAL HOME LOAN BANKS 0.6% 12/15/2025	AA+	500,000	0.600%	499,185.00	03/14/25	12/15/25		0.45%	3.989%		487,493.51
3130B1AJ6	FEDERAL HOME LOAN BANKS 5% 5/1/2026	AA+	250,000	5.000%	251,232.50	09/12/25	05/01/26		0.23%	3.617%		252,161.73
3130ARWT4	FEDERAL HOME LOAN BANKS 3.75% 11/16/2027	AA+	150,000	3.750%	149,632.50	11/04/25	11/16/27		0.13%	3.734%	5/16/26	150,045.00
3130B7LS1	FEDERAL HOME LOAN BANKS 4.2% 8/18/2028	AA+	300,000	4.200%	300,087.00	11/18/25	08/18/28		0.27%	4.105%	2/18/26	300,738.05
3130B72G8	FEDERAL HOME LOAN BANKS 4.5% 7/7/2028	AA+	300,000	4.500%	299,901.00	11/17/25	07/07/28		0.27%	4.392%	1/7/26	300,795.06
3130B44J7	FEDERAL HOME LOAN BANKS 4.62% 12/26/2028	AA+	300,000	4.620%	299,742.00	10/06/25	12/26/28		0.27%	4.510%	12/26/25	300,963.10
3130B8HB1	FEDERAL HOME LOAN BANKS 3.75% 11/5/2026		500,000	3.750%	499,310.00	11/05/25	11/05/26		0.45%	3.699%	2/5/26	500,250.00
31359YCT2	FNMA DEB-CPN 0.00% 1/15/2026		300,000	0.000%	298,548.00	05/18/21	01/05/26		0.27%	0.735%		289,926.00
31359YCT2	FNMA DEB-CPN 0.00% 1/15/2026		100,000	0.000%	99,516.00	06/02/21	01/15/26		0.09%	0.690%		96,874.00
31364EAD6	Federal Natl Mtg Assn-MTG		165,000	0.000%	161,863.35	06/02/22	05/29/26		0.15%	2.798%		147,679.95
3136GAPD5	FEDERAL NATL MTG ASSN 4.25% 08/25/2028	AA+	400,000	4.250%	399,816.00	08/26/25	08/25/28		0.36%	4.189%	2/25/26	400,680.00
3135G06Q1	FEDERAL NATL MTG ASSN 0.64% 12/30/2025	AA+	250,000	0.640%	249,337.50	07/03/25	12/30/25		0.22%	4.043%		245,898.97
912797SE8	UNITED STATES TREAS BILLS 0.000 01/06/26		500,000	0.000%	498,100.00	09/12/25	01/06/26		0.45%	3.735%		494,155.28
912797RH2	UNITED STATES TREAS BILLS 0.000 01/08/26		500,000	0.000%	497,995.00	07/18/25	01/08/26		0.45%	4.029%		490,664.17
912797SF5	UNITED STATES TREAS BILLS 0.000 01/13/26		500,000	0.000%	497,745.00	09/30/25	01/13/26		0.45%	3.691%		494,774.79
912797RJ8	UNITED STATES TREAS BILLS 0.000 01/15/26		500,000	0.000%	497,630.00	07/29/25	01/15/26		0.45%	4.078%		490,772.22
912797SG3	UNITED STATES TREAS BILLS 0.000 01/20/26		500,000	0.000%	497,360.00	09/30/25	01/20/26		0.45%	3.705%		494,403.11
912797PD3	UNITED STATES TREAS BILLS 0.000 01/22/26		500,000	0.000%	497,270.00	01/30/25	01/22/26		0.45%	4.033%		480,855.08
912797RL3	UNITED STATES TREAS BILLS 0.000 02/05/26		500,000	0.000%	496,565.00	08/08/25	02/05/26		0.45%	3.929%		490,524.89
912797SQ1	UNITED STATES TREAS BILLS 0.000 02/10/26		500,000	0.000%	496,355.00	10/21/25	02/10/26		0.45%	3.683%		494,485.56
912797RT6	UNITED STATES TREAS BILLS 0.000 02/12/26		500,000	0.000%	496,255.00	08/18/25	02/12/26		0.45%	3.907%		490,733.06
912797SR9	UNITED STATES TREAS BILLS 0.000 02/17/26		500,000	0.000%	496,005.00	10/24/25	02/17/26		0.45%	3.658%		494,324.44
912797PM3	UNITED STATES TREAS BILLS 0.000 02/19/26		500,000	0.000%	495,880.00	02/28/25	02/19/26		0.45%	4.009%		481,018.89
912797SS7	UNITED STATES TREAS BILLS 0.000 02/24/26		500,000	0.000%	495,650.00	10/31/25	02/24/26		0.45%	3.639%		494,303.50
912797ST5	UNITED STATES TREAS BILLS 0.000 03/03/26		500,000	0.000%	495,275.00	11/06/25	03/03/26		0.45%	3.584%		494,243.25
912797TA5	UNITED STATES TREAS BILLS 0.000 03/24/26		500,000	0.000%	494,165.00	11/28/25	03/24/26		0.45%	3.563%		494,324.44
912797SC2	UNITED STATES TREAS BILLS 0.000 03/26/26		500,000	0.000%	494,080.00	10/06/25	03/26/26		0.45%	3.630%		491,574.38
912797SM0	UNITED STATES TREAS BILLS 0.000 04/23/26		500,000	0.000%	492,720.00	10/30/25	04/23/26		0.44%	3.582%		491,539.24
912797SP3	UNITED STATES TREAS BILLS 0.000 05/07/26		500,000	0.000%	492,020.00	11/07/25	05/07/26		0.44%	3.597%		491,166.76
912797RR0	UNITED STATES TREAS NTS 0.000 12/02/25		500,000	0.000%	499,945.00	08/06/25	12/02/25		0.45%	3.971%		493,683.00
912797QS9	UNITED STATES TREAS NTS 0.000 12/04/25		500,000	0.000%	499,840.00	06/06/25	12/04/25		0.45%	4.067%		490,142.78
912797RW9	UNITED STATES TREAS NTS 0.000 12/09/25		500,000	0.000%	499,570.00	08/18/25	12/09/25		0.45%	3.900%		494,059.67
912797QY6	UNITED STATES TREAS NTS 0.000 12/11/25		500,000	0.000%	499,455.00	06/13/25	12/11/25		0.45%	4.067%		490,142.78
912797RY5	UNITED STATES TREAS NTS 0.000 12/23/25		500,000	0.000%	498,810.00	08/29/25	12/23/25		0.45%	3.915%		493,876.56
912797NU7	UNITED STATES TREAS NTS 0.000 12/26/25		500,000	0.000%	498,650.00	01/24/25	12/26/25		0.45%	4.035%		481,912.67
912797RZ2	UNITED STATES TREAS NTS 0.000 12/30/25		500,000	0.000%	498,440.00	09/04/25	12/30/25		0.45%	4.049%		493,560.13
912797RA7	UNITED STATES TREAS NTS 0.000 1/2/2026		500,000	0.000%	498,310.00	07/07/25	01/02/26		0.45%	4.059%		490,324.35

DETAIL OF INVESTMENT PORTFOLIO
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Alameda Municipal Power

Investment CUSIP	Investment Description	Custodian / S&P Rating	Par Value	Coupon Rate	Current Market Value	Date of Investment	Date of Maturity	ıys ıtuı	% of Portfolio	Yield to Maturity	Call Date	Book Value Purchase Price
		Subtotal	$20,065,000		19,963,623.35	Subtotal			9.83%	3.708%		19,748,905.50
	U.S. Government Bonds				0.00						0	0.00
					0.00					0.000%		0.00
	Corporate Bonds											
06368G2A4	Bank of Montreal 1.5% 10/29/2026		200,000	1.500%	192,560.00	10/27/21	10/29/26		0.17%	1.500%	1/29/26	200,000.00
06428CAA2	BANK OF AMERICA NA 5.526% 8/18/2026	A+	250,000	5.526%	252,357.50	11/04/25	08/18/26		0.23%	3.776%	7/17/26	253,382.50
06748XLS8	Barclays Bank PLC 4.35% 08/26/27	A+	550,000	4.350%	545,050.00	08/30/22	08/26/27		0.49%	4.350%	2/26/26	550,000.00
14020ADM3	Capital Impact Partners 3.9% 5/15/27	A+	500,000	3.900%	488,490.00	05/09/22	05/15/27		0.44%	3.900%		500,000.00
31424WP97	FEDERAL AGRIC MT CORP 4.2% 2/18/2027		500,000	4.200%	500,135.00	09/30/25	02/18/27		0.45%	4.051%	2/18/26	500,990.00
341081GR2	Florida PWR 4.45% 5/15/2026	A	200,000	4.450%	200,248.00	06/04/24	05/15/26		0.18%	4.938%	4/15/26	198,204.00
341081FM4	Florida Power LT Co 3.12%, 12/01/25	A+	264,000	3.125%	264,000.00	12/29/21	12/01/25		0.24%	1.419%		281,218.08
375558BF9	GILEAD SCIENCES INC 3.65% 3/1/2026	A-	250,000	3.650%	249,690.00	09/16/25	03/01/26		0.22%	3.702%	12/1/25	249,935.00
442851AQ4	HOWARD UNIV 2.291% 10/1/2026	AA	250,000	2.291%	245,515.00	07/12/22	10/01/26		0.22%	4.063%		232,977.50
459200JZ5	INTERNATIONAL BUSINESS MACHS 3.3% 5/15/202	A-	250,000	3.300%	249,215.00	09/16/25	05/15/26		0.22%	3.757%		249,250.00
53961LAK5	Local Initiatives Support Corp 1.250% 03/15/26	AA-	500,000	1.250%	495,845.00	03/22/21	03/15/26		0.45%	0.878%		500,000.00
53961LAR0	Local Initiatives Support Corp 1.250% 08/15/26	AA-	250,000	1.250%	241,375.00	08/23/21	08/15/26		0.22%	1.250%		250,000.00
74460WAA5	Public Storage 0.875% 02/15/2026	A	250,000	0.875%	248,190.00	11/09/21	02/15/26		0.22%	1.102%	1/15/26	247,637.50
78014REZ9	Royal Bk CDA, 4%, 12/30/25	A	130,000	4.000%	129,766.00	06/30/22	12/30/25		0.12%	4.000%		130,000.00
797440BU7	San Diego Gas Elec Co 2.5% 05/15/26	A	250,000	2.500%	248,150.00	07/20/21	05/15/26		0.22%	0.972%	2/15/26	267,937.50
826418BM6	Sierra Pac Pwr Co 2.6% 5/1/26	A	300,000	2.600%	298,041.00	05/17/22	05/01/26		1.02%	3.417%	2/1/26	291,000.00
83369N4G2	Societe Generale 1.05%, 03/30/26	A	300,000	1.050%	295,221.00	08/04/21	03/30/26		0.27%	1.100%	12/30/25	299,325.00
83369ND98	Societe Generale 1.3%, 10/20/2026	A	275,000	1.300%	268,837.25	10/15/21	10/20/26		0.24%	1.300%	1/20/26	275,000.00
83369M3T7	Societe Generale 1.05%, 03/31/26	A	250,000	1.050%	247,227.50	07/20/21	03/31/26		0.22%	1.110%	12/31/25	249,312.50
89236TKX2	TOYOTA MTR CR CORP 5% 8/14/2026	A+	300,000	5.000%	302,163.00	08/27/25	08/14/26		0.27%	3.894%		303,105.00
911759MZ8	U S DEPT HSG URBAN DEV GOVT 2.86% 8/1/2026		100,000	2.860%	99,261.00	10/31/25	08/01/26		0.09%	3.699%		99,382.04
911759MZ8	U S DEPT HSG URBAN DEV GOVT 2.86% 8/1/2026		300,000	2.860%	297,783.00	10/30/25	08/01/25		0.27%	3.699%		298,331.65
		Subtotal	$6,419,000		6,359,120.25				6.12%	2.813%		6,426,988.27
	Taxable Bonds Total				**26,322,743.60**							
	Municipal Bonds											
03255LKC2	ANAHEIM CALIF PUB FING AUTH LE 2.193% 7/1/2	AA	100,000	2.193%	95,654.00	6/18/25	07/01/28		0.09%	4.207%		94,315.00
03255LKC2	ANAHEIM CALIF PUB FING AUTH LE 2.193% 7/1/2	AA	150,000	2.193%	143,481.00	8/4/25	07/01/28		0.13%	4.001%		142,620.00
072024WR9	BAY AREA TOLL AUTH CALIF TOLL 2.425% 4/1/202	AA	300,000	2.425%	298,650.00	01/15/25	04/01/26		0.27%	4.258%		293,565.00
072024WR9	BAY AREA TOLL AUTH CALIF TOLL 2.425% 4/1/202	AA	200,000	2.425%	199,100.00	06/03/25	04/01/26		0.18%	4.040%		197,390.00
072024XC1	Bay Area Toll Auth Calif Toll - 1.079%, 04/01/2026	AA	400,000	1.079%	396,352.00	01/13/23	04/01/26		0.36%	4.299%		361,688.00
13063DGC6	CALIFORNIA ST GENERAL OBLIGATION UNLTD 3.5% 4/1/2028		50,000	3.500%	49,811.00	04/07/25	04/01/28		0.04%	3.939%		49,387.50
13063DGC6	CALIFORNIA ST GENERAL OBLIGATION UNLTD 3.5	AA-	250,000	3.500%	249,055.00	08/11/25	04/01/28		0.22%	3.854%		247,790.00
13063DMA3	CALIFORNIA ST GENERAL OBLIGATION UNLTD 2.6	AA-	500,000	2.650%	498,090.00	05/08/24	04/01/26		0.45%	4.933%		479,550.00
13063DRD2	CALIFORNIA ST GENERAL OBLIGATION UNLTD 2.3	AA-	275,000	2.375%	272,046.50	08/03/23	10/01/26		0.25%	4.656%		256,811.50
13063DRD2	CALIFORNIA ST GENERAL OBLIGATION UNLTD 2.3	AA-	100,000	2.375%	98,926.00	07/03/25	10/01/26		0.09%	3.818%		98,260.00
13063DRE0	CALIFORNIA ST GENERAL OBLIGATION UNLTD 2.5	AA-	100,000	2.500%	95,671.00	06/03/25	10/01/29		0.09%	4.181%		93,405.00
13077DKF8	CALIFORNIA ST UNIV REV TAXABLE SYSTEMWIDE	AA-	100,000	2.001%	96,869.00	06/18/25	11/01/27		0.09%	3.973%		95,580.00
13063DC48	CALIFORNIA ST TAXABLE VARIOUS PURP GO 1.7%	AA-	250,000	1.700%	239,867.50	04/03/25	02/01/28		0.22%	4.029%		234,577.50
15722TJT9	CHABOT-LAS POSITAS CALIF CMNTY REF 1.517% 8	AA	100,000	1.517%	94,181.00	09/04/25	08/01/28		0.08%	3.693%		94,050.00
197036JR8	COLTON CA JT USD GO SCH BDS 2011C TXBL 6.00	A+	100,000	6.008%	101,373.00	03/12/25	08/01/26		0.09%	4.627%		101,828.00
283062FE2	EL DORADO CALIF IRR DIST REV TAXABLE BDS 3.41	AA	150,000	3.418%	149,928.00	05/08/25	01/01/26		0.14%	4.024%		149,419.50
292521GR6	ENCINITAS CALIF PUB FING AUTH LEASE REV 1.46% 10/1/2027		100,000	1.460%	95,618.00	04/03/25	10/01/27		0.09%	4.217%		93,537.00
427078AG5	Hercules Calif Redev Agy Succe	AA	250,000	3.850%	249,595.00	08/17/22	08/01/26		0.22%	3.238%		255,622.50
53820AAH7	LIVERMORE CALIF REC & PK DISTP 1.915% 2/1/20	AA	100,000	1.915%	93,980.00	07/03/25	02/01/29		0.08%	4.067%		92,899.00
538310P80	LIVERMORE VLY CA JT UNIF SCH DIST 1.566% 8/1/2027		100,000	1.566%	96,319.00	03/12/25	08/01/27		0.09%	4.185%		94,110.00
544445TW9	LOS ANGELES CALIF DEPT ARPTS 1.101% 5/15/202	AA-	300,000	1.101%	288,864.00	08/03/23	05/15/27		0.26%	4.933%		260,865.00
544646A69	LOS ANGELES CALIF UNI SCH DIST 5.981% 5/1/202	AA-	200,000	5.981%	206,522.00	10/16/24	05/01/27		0.19%	4.307%		207,976.00
546462EH1	Louisiana St Energy and Pwr	AA	250,000	1.433%	246,870.00	03/17/22	06/01/26		0.22%	2.891%		235,657.50

DETAIL OF INVESTMENT PORTFOLIO
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Alameda Municipal Power

Investment CUSIP	Investment Description	Custodian / S&P Rating	Par Value	Coupon Rate	Current Market Value	Date of Investment	Date of Maturity	ys tu	% of Portfolio	Yield to Maturity	Call Date	Book Value Purchase Price
612286FE9	MONTEBELLO CALIF PUB FING AUTH 5.45% 11/1/2026		100,000	5.450%	101,160.00	09/04/25	11/01/26		0.09%	3.762%		101,890.00
64966WGZ4	New York NY City HSG Dev Corp 3.281% 1/1/2026	AA-	300,000	3.281%	299,835.00	04/12/22	01/01/26		0.27%	3.058%		302,325.00
725894FZ7	PLACENTIA-YORBA LINDA CALIF UN GO BDS 5.79%	AA	500,000	5.790%	506,155.00	11/04/25	08/01/26		0.46%	3.731%		507,430.00
77781RCR2	ROSEVILLE CA FIN AUTH ELEC SYS REV BOND 1.11	AA	150,000	1.111%	149,305.50	05/02/22	02/01/26		0.13%	3.548%		137,293.50
797272RQ6	SAN DIEGO CALIF CMNTY COLLEGED 1.763% 8/1/2	AAA	100,000	1.763%	95,116.00	07/03/25	08/01/28		0.09%	3.859%		93,970.00
79730WBC3	SAN DIEGO CALIF REDEV AGY SUCC 3.75% 9/1/20	AA	50,000	3.750%	49,964.00	09/30/24	09/01/26		0.05%	3.995%		49,775.00
79766DNZ8	SAN FRANCISCO CALIF CITY & CNT 3.288% 1/1/20	A+	250,000	3.288%	249,842.50	09/11/24	01/01/26		0.23%	4.555%		246,032.50
798153NG3	SAN JOSE CA FING AUTH LEASE REVENUE 1.461% 6/1/2027		100,000	1.461%	96,447.00	09/04/25	06/01/27		0.09%	3.646%		96,372.00
798170AJ5	SAN JOSE CA REDEV AGY SUCCESSOR AGY TAX 3.176% 8/1/2026		100,000	3.176%	99,510.00	09/04/25	08/01/26		0.09%	3.677%		99,550.00
798170AJ5	SAN JOSE CA REDEV AGY SUCCESSOR AGY TAX 3.176% 8/1/2026		300,000	3.176%	298,530.00	09/09/25	08/01/26		0.27%	3.677%		299,010.00
799038NS9	SAN MATEO CNTY CA CMNTY CLG 1.467% 9/1/2027		100,000	1.467%	96,471.00	04/03/25	09/01/27		0.09%	4.050%		94,170.00
7994082H1	SAN RAMON VALLEY CALIF UNI SCH 1.67%	AA	125,000	1.670%	118,846.25	08/04/25	08/01/28		0.11%	4.064%		116,727.50
83789TBU2	SOUTH GATE CALIF UNTIL AUTH WTR 2.748% 10/1	AA-	100,000	2.748%	97,093.00	07/03/25	10/01/28		0.09%	3.978%	10/01/27	96,315.00
791526RZ1	St. Louis Cnty Mo Spl Oblig	AA	150,000	1.000%	150,000.00	03/08/21	12/01/25	##	0.14%	0.881%		150,823.50
91412GE43	UNIV OF CALIFORNIA CA REVENUES 2.837% 5/15/	AA	300,000	2.837%	293,463.00	07/03/25	05/15/28		0.26%	3.875%		291,687.00
91412GXS9	UNIVERSITY CALIF REVS FOR PREV LTD 3.659% 5/1	AA-	200,000	3.659%	199,672.00	09/04/25	06/15/27		0.18%	3.594%		200,182.00
91412HJQ7	UNIV OF CALIFORNIA CA REVS TAXABLE GEN 1.69	AA	100,000	1.697%	93,492.00	06/18/25	05/15/29		0.08%	4.155%		91,295.00
91412HJQ7	UNIV OF CALIFORNIA CA REVS TAXABLE GEN 1.69	AA	150,000	1.697%	140,238.00	08/20/25	05/15/29		0.13%	3.986%		138,288.00
95236PGD6	W Covina CA Pub Fing Auth 2.538% 8/1/2026	A+	300,000	2.538%	297,051.00	09/01/21	08/01/26	##	0.27%	1.090%		320,739.00
		Subtotal	$7,650,000		**7,789,014.25**			##	6.80%	3.846%		7,664,779.00
	Certificates of Deposit											
06053CDD5	BANK AMER CALIF NATL ASSN SAN 4.15% 2/12/2026		250,000	4.150%	250,075.00	02/12/25	02/12/26		0.23%	4.150%		250,000.00
05610LTD6	BMO BK NATL ASSN CHICAGO ILL 4.15% 12/31/2025		250,000	4.150%	250,042.50	03/31/25	12/31/25		0.23%	4.143%		250,000.00
05584CX68	BNY MELLON NA INSTL CTF DEP 4.05% 2/12/2026		250,000	4.050%	250,042.50	05/12/25	02/12/26		0.23%	4.043%		250,000.00
14042RWU1	CAPITAL ONE NATL ASSN VA CD 3.55% 11/15/2027		250,000	3.550%	249,260.00	11/13/25	11/15/27		0.22%	3.550%		250,000.00
15118RWW3	Celtic Bk Salt Lake City Utah 1.00% 12/22/2025		200,000	1.000%	199,622.00	11/12/21	12/22/25		0.18%	1.000%		200,000.00
29978MGE2	EVERBANK N A JACKSONVILLE FLA 3.7% 04/30/2026		250,000	3.700%	249,857.50	10/30/25	04/30/26		0.23%	3.700%		250,000.00
32110YXF7	First Natl Bk Amer East Lans, 3%, 06/17/26		275,000	3.000%	273,798.25	06/17/22	06/17/26		0.25%	3.000%	12/17/25	275,000.00
33646CNH3	First Source Bk South Bend, 5% 6/16/27		150,000	5.000%	150,018.00	12/12/22	06/16/27		0.14%	5.000%	12/16/25	150,000.00
38150V4K2	GOLDMAN SACHS BK USA CD 4.05% 5/12/2026		250,000	4.050%	250,215.00	08/12/25	05/12/26		0.23%	4.043%		250,000.00
48128UVB2	JP Morgan Chase 0.60% 6/29/2026		300,000	0.600%	294,471.00	06/11/21	06/29/26	##	0.27%	0.836%	12/29/25	296,509.32
60700PL41	MIZUHO BK USA 4% 2/27/2026		250,000	4.000%	250,050.00	08/27/25	02/27/26		0.23%	4.000%		250,000.00
61776CVK0	MORGAN STANLEY BK N A 4.3% 7/31/2028		250,000	4.300%	250,037.50	07/31/25	07/31/28		0.23%	4.300%	1/31/26	250,000.00
69355NKL8	PNC BANK NATIONAL ASSOCIATION 4.2% 2/2/2026		250,000	4.200%	250,120.00	07/31/25	02/02/26		0.23%	4.200%		250,000.00
83407DCF1	SOFI BANK NATIONAL ASSOCIATON 4.25% 5/1/2026		250,000	4.250%	250,392.50	07/31/25	05/01/26		0.23%	4.242%		250,000.00
949764QQ0	WELLS FARGO BANK NATL ASSN 4.25% 12/11/2025		250,000	4.250%	250,027.50	03/11/25	12/11/25		0.23%	4.242%		250,000.00
98970LKZ5	ZIONS BANCORPORATION NATL ASSN 3.75% 4/15/2026		250,000	3.750%	249,900.00	10/15/25	04/15/26		0.23%	3.750%		250,000.00
		Total	$3,925,000		3,917,929.25			##	3.08%	3.637%		3,921,509.32
		Grand Total			**110,998,698.13**	**Weighted Average Interest Rate**				**3.916%**		**110,731,193.12**

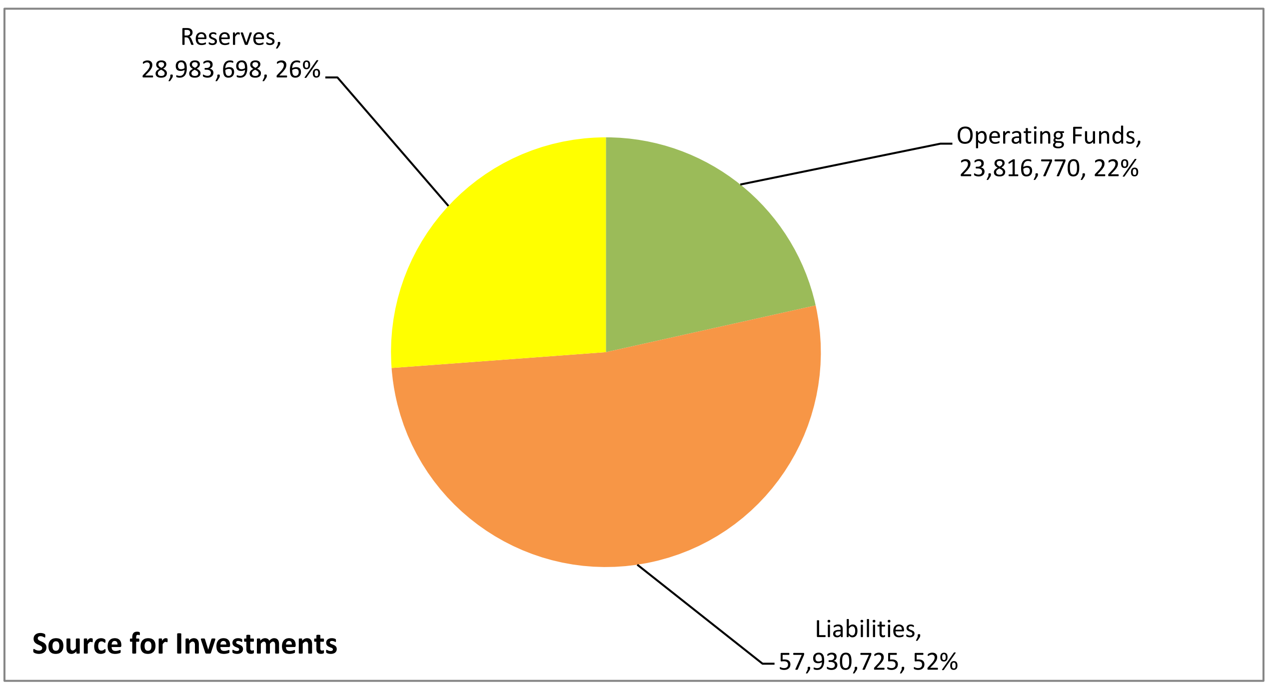
(1) Portfolio details are based on available third-party statements as of 11/30/2025

Prepared by: Charlene L.

Alameda Municipal Power
Supplemental Schedule
Sources of Investments & Investment Portfolio
November 30, 2025

SOURCES FOR INVESTMENTS

	Account		
Operating Funds			$23,816,770
Liabilities			
Balancing Account	10 3401		57,926,500
Donations to Alameda United School District	10 3151		4,224
Reserves For Special Purposes			
Insurance Reserve Special Fund	10 2107		1,200,000
Underground Fund Carryforward 10/31/2025	10 2111	$ 10,641,306	
Fiscal Year (FY) 2026 - Nov. 2025 Undergrounding Funding	10 2111	132,672.08	
Underground Special Fund Used in Nov. 2025 - FY 2026	10 2111	(1,564,078)	
Net - Underground Fund Available (Deficiency)			9,209,900
Renewable Energy Credits Net Revenue Reserve	10 2113		16,332,196
Cap & Trade Net Revenue Reserve	10 2114		1,453,263
Low Carbon Fuel Standards Revenue Reserve	10 2115		788,339
Total Sources For Investments			$110,731,193



AGENDA ITEM NO.: 4.E.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: 2026-39
ACTION: BY MOTION

To: Honorable Public Utilities Board

Submitted by: /S/
Teri Dean Alderson
AGM – Administration

From: Heather Heinbaugh
Financial & Utility Billing Manager

Approved by: /S/
Tim Haines
General Manager

Subject: By Motion, Accept the Independent Audit and its Associated Reports From Maze & Associates of Alameda Municipal Power's Financial Position for the Fiscal Year Ending on June 30, 2025, and Find the Action Exempt from the California Environmental Quality Act

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RECOMMENDATION

By motion, find AMP's action is not a CEQA project pursuant to CEQA Guidelines Section 15378, is exempt from the California Environmental Quality Act pursuant to CEQA Guidelines Sections 15061(b)(3) and 15378 for the reasons outlined in the administrative report, and accept the independent audit and its associated reports from Maze & Associates of Alameda Municipal Power's financial position for the fiscal year ending on June 30, 2025.

BACKGROUND

The City of Alameda's Charter (Article XII Sec 12-4[B]) and California state law require an annual audit of Alameda Municipal Power (AMP) by independent Certified Public Accountants (CPA). AMP contracted with Maze & Associates as its CPA firm to perform the audit.

DISCUSSION

The annual audit process produces a variety of written documentation on AMP's financial position through June 30, the fiscal year end. The documentation for fiscal year (FY) 2025 provides detailed financial information by which the Public Utilities Board (Board), City Council, the public, market analysts, investors, and other interested parties, may assess the current state of AMP's business affairs and compare its performance to previous fiscal years.

Included in this year's documentation are:

1. A memo from the independent auditor describing Internal Control and required communication based on an audit of Financial Statements performed in accordance with Government Auditing Standards (Exhibit A).

2. AMP's Annual Comprehensive Financial Report (ACFR) for the fiscal years ending on June 30, 2025, and June 30, 2024 (Exhibit B).

AMP's management team is responsible for both the accuracy of the data contained in the ACFR and the completeness and fairness of the presentation, including all disclosures. To the best of our knowledge and belief, the data presented is accurate in all material respects and is reported in a manner that impartially sets forth the financial position and operational results of AMP. It should be noted that the independent auditor has expressed in their Independent Auditors' Report, which is included in the financial section of the ACFR, that "In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of AMP as of June 30, 2025 and 2024, and the changes in its financial position and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America."

The letter from the independent auditor describing observations related to internal control, compliance, and other matters based on an audit of financial statements performed in accordance with government auditing standards is included in the ACFR beginning on page 107.

AMP has continued to meet and exceed best practices in government finance. The Memo on Internal Control (MOIC) from the independent auditor describing Significant Audit Findings (Exhibit A) affirms that the audit was conducted in accordance with generally accepted auditing standards and that AMP management was responsible for the selection and use of appropriate accounting policies. The auditor noted:

1. There were no transactions entered into by AMP during the year for which there was a lack of authoritative guidance.

2. All significant transactions have been recognized in the financial statements in the proper period.

3. There were no difficulties or disagreements encountered.

The ACFR for FY 2025 (Exhibit B), with its comparative amounts to previous years, has been prepared to meet the needs of a broad spectrum of financial statement readers.

The ACFR is divided into the following sections:

- *Introductory Section*: This section introduces the reader to AMP and includes a transmittal letter from the General Manager highlighting AMP's history, its recent accomplishments, and some of the economic conditions within which AMP operates.

- *Financial Section*: This section introduces the reader to specific financial data and includes the independent auditors' report, management's discussion and analysis letter, financial statements, and notes to the financial data.

- *Statistical Section*: This section introduces the reader to the history of AMP through a variety of tables and graphs revealing the long-term results of AMP's operations, the City's demographics, and miscellaneous data that complements the financial data. Although this section contains substantial financial data, the tables and graphs differ from financial statements in that they present some non-accounting data, cover more than the current year, and are designed to reflect social and economic data, financial trends, and the fiscal capabilities of AMP.

- *Bond Disclosure Section*: This section introduces the reader to consolidated information which was previously transmitted separately as part of required bond disclosures. The information presented is for AMP's five most recent fiscal years and includes those years ended June 30, 2025; 2024; 2023; 2022; and 2021.

FINANCIAL IMPACT

None.

ENVIRONMENTAL REVIEW

Alameda Municipal Power finds that its actions are not a project as defined by CEQA Guidelines Section 15378, which excludes "continuing administrative…activities" and "organization or administrative activities of governments…" Alameda Municipal Power further finds that it can be seen with certainty that there is no possibility that the activity will result in a direct or reasonably foreseeable indirect change in the environment. The project involves the disclosure of factual information pursuant to statutory mandates, and there is no potential for direct or indirect changes in existing conditions as a result.

Alameda Municipal Power further finds that its actions are exempt CEQA pursuant to CEQA Guidelines §§ 15268, which excludes ministerial actions. More specifically, Alameda Municipal Power finds its action is subject to the commonsense exemption because it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

NEXT STEPS

After acceptance by the Board, the ACFR for FY 2025 will be on file with the City Clerk and can also be reviewed at the Alameda Free Library and its branches. Additionally, the ACFR will be added to AMP's website and, in accordance with policy and lending institution covenant, will be distributed to several parties outside of AMP.

EXHIBITS

A. Memo On Internal Control from the independent auditor describing Internal Control Over Financial Reporting and other Matters based on an audit of Financial Statements performed in accordance with Government Auditing Standards (GAS)

B. AMP's Annual Comprehensive Financial Report (ACFR) for the fiscal years ending on June 30, 2025, and June 30, 2024

AGENDA ITEM NO.: 4.E
MEETING DATE: 01/12/2026

EXHIBIT A

ALAMEDA MUNICIPAL POWER
MEMORANDUM ON INTERNAL CONTROL
AND
REQUIRED COMMUNICATIONS

FOR THE YEAR ENDED JUNE 30, 2025

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ALAMEDA MUNICIPAL POWER
MEMORANDUM ON INTERNAL CONTROL
AND
REQUIRED COMMUNICATIONS

For The Year Ended June 30, 2025

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MEMORANDUM ON INTERNAL CONTROL

Public Utilities Board
Alameda Municipal Power
Alameda, California

In planning and performing our audit of the basic financial statements of the Alameda Municipal Power (AMP) as of and for the year ended June 30, 2025, in accordance with auditing standards generally accepted in the United States of America, we considered AMP's internal control over financial reporting (internal control) as a basis for designing audit procedures that are appropriate in the circumstances for the purpose of expressing our opinions on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of AMP's internal control. Accordingly, we do not express an opinion on the effectiveness of AMP's internal control.

A deficiency in internal control exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct misstatements on a timely basis. A material weakness is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of AMP's financial statements will not be prevented, or detected and corrected, on a timely basis.

Our consideration of internal control was for the limited purpose described in the first paragraph and was not designed to identify all deficiencies in internal control that might be material weaknesses. In addition, because of inherent limitations in internal control, including the possibility of management override of controls, misstatements due to error or fraud may occur and not be detected by such controls. Given these limitations, during our audit, we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

This communication is intended solely for the information and use of management, Public Utilities Board, others within the organization, and agencies and pass-through entities requiring compliance with *Government Auditing Standards*, and is not intended to be and should not be used by anyone other than these specified parties.

Maze + Associates

Pleasant Hill, California
December 4, 2025

Accountancy Corporation
3478 Buskirk Avenue, Suite 217
Pleasant Hill, CA 94523

T 925.228.2800
E maze@mazeassociates.com
W mazeassociates.com

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REQUIRED COMMUNICATIONS

Public Utilities Board
Alameda Municipal Power
Alameda, California

We have audited the basic financial statements of the Alameda Municipal Power (AMP) for the year ended June 30, 2025. Professional standards require that we provide you with information about our responsibilities under generally accepted auditing standards and *Government Auditing*, as well as certain information related to the planned scope and timing of our audit. We have communicated such information in our letter to you dated June 3, 2025. Professional standards also require that we communicate to you the following information related to our audit.

Significant Audit Matters

Qualitative Aspects of Accounting Practices

Accounting Policies – Management is responsible for the selection and use of appropriate accounting policies. The significant accounting policies used by AMP are described in Note 1 to the financial statements. No new accounting policies were adopted, and the application of existing policies was not changed during the year, except as follows:

GASB 101 – *Compensated Absences*

GASB 102 – *Certain Risk Disclosures*

These pronouncements became effective, but did not have a material effect on the financial statements.

Unusual Transactions, Controversial or Emerging Areas – We noted no transactions entered into by AMP during the year for which there is a lack of authoritative guidance or consensus. All significant transactions have been recognized in the financial statements in the proper period.

Accounting Estimates – Accounting estimates are an integral part of the financial statements prepared by management and are based on management's knowledge and experience about past and current events and assumptions about future events. Certain accounting estimates are particularly sensitive because of their significance to the financial statements and because of the possibility that future events affecting them may differ significantly from those expected. The most sensitive estimates affecting AMP's financial statement were:

> *Estimated Fair Value of Investments:* As of June 30, 2025, the AMP held approximately $126.2 million of cash and investments as measured by fair value as disclosed in Note 2 to the financial statements. Fair value is essentially market pricing in effect as of June 30, 2025. These fair values are not required to be adjusted for changes in general market conditions occurring subsequent to June 30, 2025.

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Estimate of Depreciation: Management's estimate of the depreciation is based on useful lives determined by management. These lives have been determined by management based on the expected useful life of assets as disclosed in Note 1 to the financial statements. We evaluated the key factors and assumptions used to develop the depreciation estimate in determining that it is reasonable in relation to the basic financial statements taken as a whole.

Estimated Net Pension Liabilities and Pension-Related Deferred Outflows and Inflows of Resources: Management's estimate of the net pension liabilities and deferred outflows/inflows of resources are disclosed in Note 6 to the financial statements and are based on actuarial studies determined by a consultant, which are based on the experience of the AMP. We evaluated the key factors and assumptions used to develop the estimate in determining that it is reasonable in relation to the basic financial statements taken as a whole.

Estimated Net OPEB Liabilities and OPEB-Related Deferred Outflows and Inflows of Resources: Management's estimate of the net OPEB liabilities and deferred outflows/inflows of resources are disclosed in Note 7 to the financial statements and are based on actuarial studies determined by a consultant, which are based on the experience of the AMP. We evaluated the key factors and assumptions used to develop the estimate in determining that it is reasonable in relation to the basic financial statements taken as a whole.

Disclosures – The financial statement disclosures are neutral, consistent, and clear.

Difficulties Encountered in Performing the Audit

We encountered no significant difficulties in dealing with management in performing and completing our audit.

Corrected and Uncorrected Misstatements

Professional standards require us to accumulate all known and likely misstatements identified during the audit, other than those that are clearly trivial, and communicate them to the appropriate level of management. We did not propose any audit adjustments that, in our judgment, could have a significant effect, either individually or in the aggregate, on AMP's financial reporting process.

Professional standards require us to accumulate all known and likely uncorrected misstatements identified during the audit, other than those that are trivial, and communicate them to the appropriate level of management. We have no such misstatements to report to the Board.

Disagreements with Management

For purposes of this letter, a disagreement with management is a financial accounting, reporting, or auditing matter, whether or not resolved to our satisfaction, that could be significant to the financial statements or the auditor's report. We are pleased to report that no such disagreements arose during the course of our audit.

Management Representations

We have requested certain representations from management that are included in a management representation letter dated December 4, 2025.

Management Consultations with Other Independent Accountants

In some cases, management may decide to consult with other accountants about auditing and accounting matters, similar to obtaining a "second opinion" on certain situations. If a consultation involves application of an accounting principle to AMP's financial statements or a determination of the type of auditor's opinion that may be expressed on those statements, our professional standards require the consulting accountant to check with us to determine that the consultant has all the relevant facts. To our knowledge, there were no such consultations with other accountants.

Other Audit Findings or Issues

We generally discuss a variety of matters, including the application of accounting principles and auditing standards, with management each year prior to retention as AMP's auditors. However, these discussions occurred in the normal course of our professional relationship and our responses were not a condition to our retention.

Other Matters

We applied certain limited procedures to the required supplementary information that accompanies and supplements the basic financial statements. Our procedures consisted of inquiries of management regarding the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We did not audit the required supplementary information and do not express an opinion or provide any assurance on the required supplementary information.

We were not engaged to report on the Introductory and Statistical Sections which accompany the financial statements, but are not required supplementary information. Such information has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on them.

******

This information is intended solely for the use of the Public Utilities Board and management and is not intended to be, and should not be, used by anyone other than these specified parties.

Maze + Associates

Pleasant Hill, California
December 4, 2025

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AGENDA ITEM NO.: 4.E
MEETING DATE: 01/12/2026
EXHIBIT B

Annual Comprehensive **Financial Report**

FOR THE YEARS ENDED
JUNE 30, 2025 AND JUNE 30, 2024

An Enterprise Fund and Department of the City of Alameda
Alameda, CA

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

Public Utilities Board

(as of 06/30/2025)

PRESIDENT
Christina Nagy McKenna

VICE PRESIDENT
Elise Hunter

COMMISSIONER
Ryan Bird

COMMISSIONER
Nick de Vries

CITY MANAGER
Jennifer Ott

Alameda Municipal Power

(as of 06/30/2025)

GENERAL MANAGER
Timothy Haines

ASSISTANT GENERAL MANAGER, ADMINISTRATION
Teri Dean Alderson

ASSISTANT GENERAL MANAGER, CUSTOMER & ENERGY RESOURCES
Chris Ferrara

INTERIM ASSISTANT GENERAL MANAGER, ENGINEERING & OPERATIONS
Alan Harbottle

Alameda Municipal Power
A Department of the City of Alameda

2000 Grand Street | Alameda, CA 94501 | (510) 748-3900 | www.alamedamp.com

ALAMEDA MUNICIPAL POWER

AN ENTERPRISE FUND AND DEPARTMENT OF THE CITY OF ALAMEDA, CALIFORNIA

ANNUAL COMPREHENSIVE FINANCIAL REPORT

FISCAL YEARS ENDED JUNE 30, 2025 AND 2024

PREPARED BY THE

ADMINISTRATION DIVISION

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Introductory Section

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ALAMEDA MUNICIPAL POWER
AN ENTERPRISE FUND AND DEPARTMENT
OF THE CITY OF ALAMEDA
ANNUAL COMPREHENSIVE FINANCIAL REPORT
FISCAL YEARS ENDED JUNE 30, 2025 AND 2024

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ALAMEDA MUNICIPAL POWER
AN ENTERPRISE FUND AND DEPARTMENT
OF THE CITY OF ALAMEDA
ANNUAL COMPREHENSIVE FINANCIAL REPORT
FISCAL YEARS ENDED JUNE 30, 2025 AND 2024

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STATISTICAL SECTION

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BOND DISCLOSURE SECTION

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December 4, 2025

To the Public Utilities Board and Our Customers:

We are pleased to transmit the Annual Comprehensive Financial Report (ACFR) of Alameda Municipal Power (AMP), an enterprise fund and department of the City of Alameda, California for the fiscal year ended June 30, 2025 and a comparative to fiscal year ended June 30, 2024. AMP encourages readers to review all sections of this report and especially requests that they refer to Management's Discussion and Analysis located in the Financial Section of this report.

Responsibility for both the accuracy of the data, and the completeness and fairness of the presentation, including all disclosures, rests with AMP's management. AMP believes that the data presented here is accurate in all material respects, that the data is presented in a manner designed to set forth fairly the financial position of the organization and that all disclosures necessary to gain an understanding of the financial activity are included in this report.

Profile

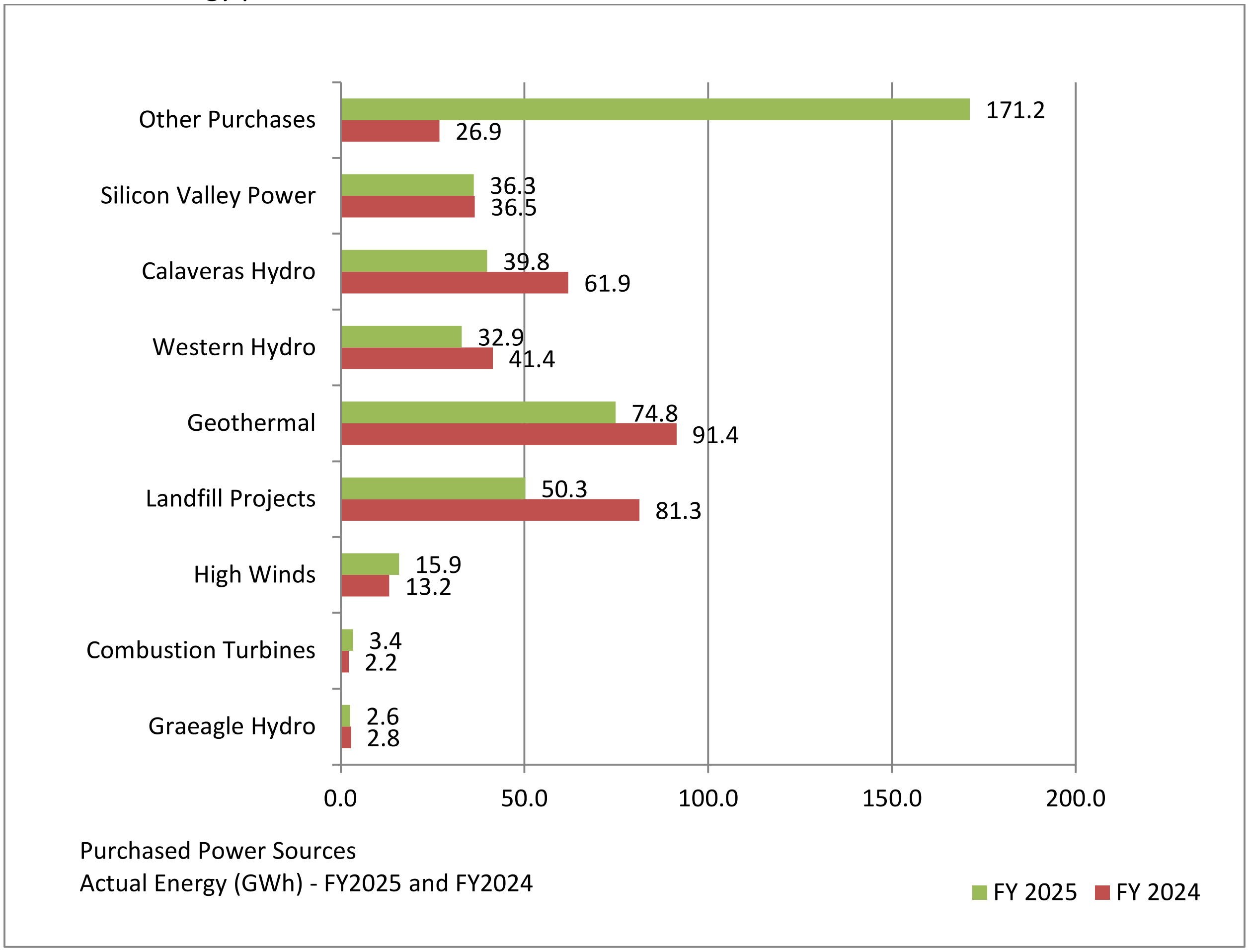
The City of Alameda - Department of Public Utilities - Alameda Municipal Power, is the oldest municipal electric utility in California and is amongst the oldest in the nation, either public or private. The municipal utility has safely provided reliable, cost-effective, and environmentally responsible, electric-energy services since its founding in 1887.

AMP is governed by a Public Utilities Board (Board). Pursuant to the Alameda City Charter, the Board has the power to control and manage the electric system, including the power to fix rates for the services provided by AMP. The Board establishes goals and policies, approves major purchases, and creates the framework for local control of AMP. The Board is comprised of four commissioners (appointed by the Mayor with concurrence from the City Council) and the City Manager (as an ex-officio member). At the start of fiscal year (FY) 2025, the members of the Board included President Christina McKenna, Vice President Elise Hunter, Commissioner Jerry Serventi, Commissioner Ryan Bird, and City Manager Jennifer Ott. The appointments for Board commissioners became effective October 2024 and the appointment for City Manager became effective January 2023. After eight years of distinguished service, Commissioner Jerry Serventi's time on AMP's Board concluded in March 2025. The Board members comprised of President Christina McKenna, Vice President Elise Hunter, Commissioner Ryan Bird, Commissioner Nick de Vries, and City Manager Jennifer Ott as of June 30, 2025.

The City of Alameda is an island community of 22.8 square miles located across the bay from San Francisco and to the southwest of the City of Oakland. Alameda Municipal Power (hereinafter, "AMP") serves the entire area of the City of Alameda and has about 86 pole miles of overhead distribution lines and 200 circuit miles of underground distribution lines, 6.8 pole miles of overhead transmission lines, 1.9 underground circuit miles. During FY 2025, AMP served an average of 37,070 customers, comprised of an average of 32,877 residential customers, an average of 3,833 commercial customers and an average of 360 public authority and other customers, with a peak demand of approximately 67 MW.

AMP does not independently own any generation assets at this time; but rather, it procures power through long and short-term agreements. To facilitate the acquisition of power, AMP joined the Northern California Power Agency (NCPA) in 1968. NCPA is a joint-powers agency composed of AMP and 14 other northern California public entities. NCPA provides electric scheduling, dispatch and transmission for the provision of AMP's electric-energy services. AMP participates in the NCPA power pool and makes short-term market purchases and sales as necessary, or economical, to meet its native load requirements and dispose of surplus. Generally, AMP has entered into power purchase agreements solely or primarily for use within its own system. AMP continues its program to research, solicit and acquire electric generation sources that are economical, provide stable costs over the long-term, and are environmentally responsible.

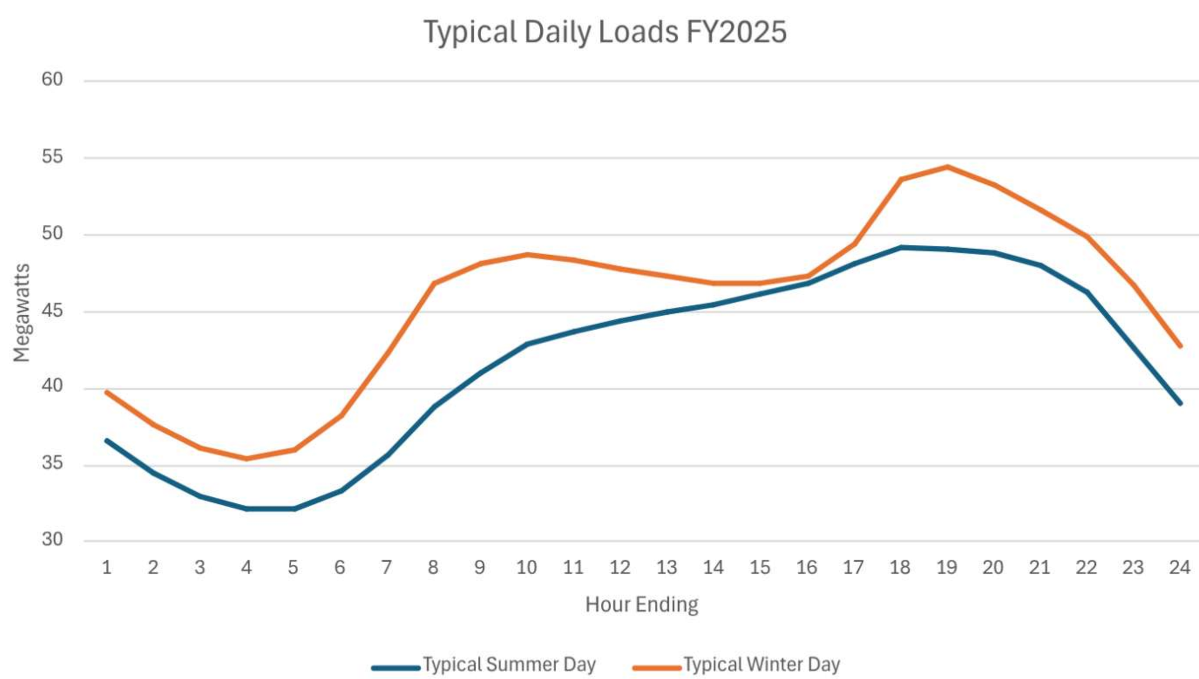
The actual energy purchased is illustrated below:



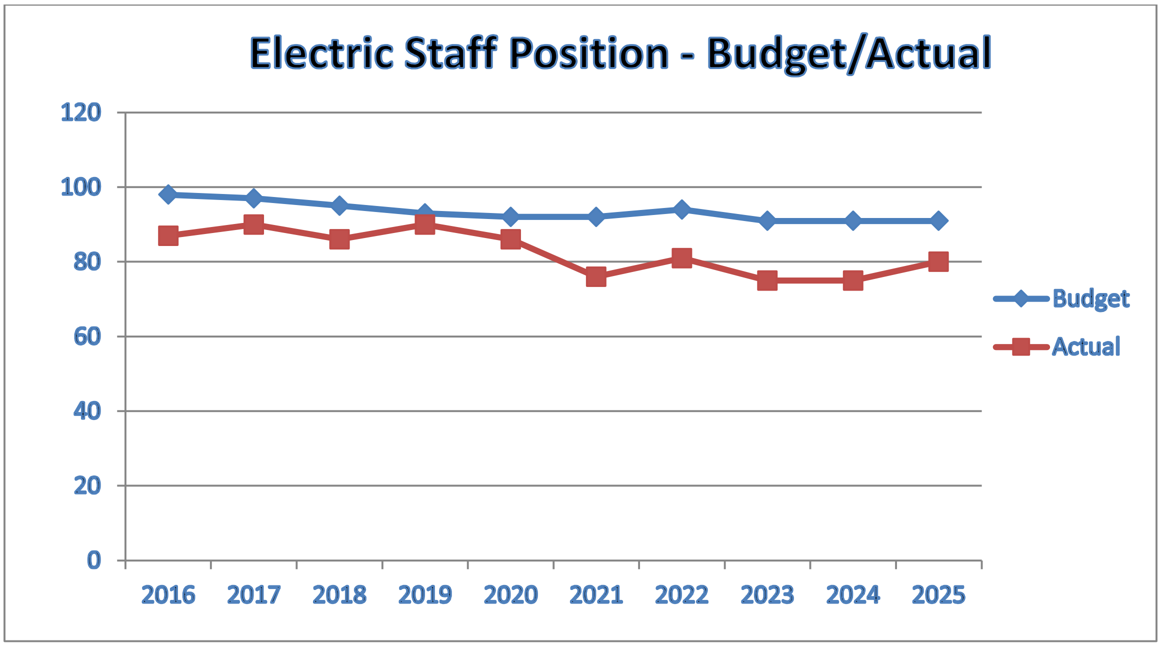
AMP participates in most of NCPA's generation projects, but it does not participate in the Lodi Energy Center. Approximately 25.1% of AMP's resources in FY 2025 were sourced through NCPA projects including 9.3% from the Calaveras hydroelectric facilities, 15% from the Geothermal plants, and 0.8% from the Combustion Turbine (CT) projects. In addition, AMP sourced 7.7% from the Western Area Power Administration's (WAPA) hydroelectric facilities and 0.6% from the Graeagle hydroelectric facilities in a coordinated effort with NCPA.

AMP procured the remaining approximately 74.9% of its power supply resources independent of NCPA and has obtained independent contracts for several landfill gas facilities, a baseload winter renewables contract with Silicon Valley Power, and for a portion of the high winds project. NCPA provides electric scheduling, dispatch and transmission for these electric-energy services. Per the Alameda Public Utilities Board direction, AMP began renewable energy certificate (REC) sales in January 2025, selling off AMP's share of geothermal energy and our share of Ox Mountain landfill energy. To maintain AMP's strategic goal of providing 100% clean energy to our customers, AMP offsets the REC sales by purchasing hydroelectric energy for the duration of the REC sales. The power supply used to serve AMP's customers is reported and verified on a calendar year basis to the California Energy Commission (CEC) via the Power Source Disclosure Report and data from the report is used to publish AMP's Power Content Label which shows our electric portfolio's power mix and emissions intensity associated with our customers.

Each year, the energy output from the generating facilities is optimized based upon seasonal, economic and maintenance considerations. The chart below indicates the electric system's maximum average daily load occurs about 7:00 pm during the winter and the minimum average daily load occurs about 4:00 am during the summer. This data is used by AMP to review system capacity needs and trends for time-of-use rate planning.



AMP's employees keep the system operational 24 hours a day, 7 days a week. The utility's professionals are represented by Alameda Municipal Power Unrepresented Employees ("AMPU") and the Electric Utility Professionals of Alameda ("EUPA"). Non-management personnel are represented by either the International Brotherhood of Electrical Workers ("IBEW") or the Alameda City Employees Association ("ACEA"). The last Memoranda of Understanding (MOU) expired June 2025. The City completed negotiations with EUPA, AMPU, IBEW, and ACEA and the new MOUs for the period commencing July 1, 2025 and ending June 30, 2027 were adopted. Employee retirement benefits are provided by AMP through the City of Alameda's participation in the California Public Employees Retirement System ("CalPERS").



AMP refinanced $31.7 million of its electric debt during August 2010 into fixed rate bonds. The Board continues to adhere to financial guidelines, set specific reserve targets and affirm rate principles.

In January 2019, the Board accepted the five-year strategic plan that will enable AMP to meet its obligations as Alameda's municipal electric provider for 2020 through 2025. Critical elements that will determine AMP's future direction include global issues, issues within Alameda, critical stakeholders, priorities, mission, vision, values, and key performance indicators (KPI).

The strategic plan is based on five main issues:

1) Sustainability
   - Manage triple bottom line (economic/environmental/social) performance to support a sustainable Alameda
     - Deliver and maintain 100% clean energy resources by 2020 and beyond

  - Support opportunities in the electrification of the transportation system and buildings to reduce Green House Gas (GHG) emissions

2) Customer Experience

- ❖ Increase value to the community through meaningful programs and services, positive customer interactions, and building the brand
  - Define and promote brand to improve awareness and value
  - Build an employee culture that consistently promotes value and principles of public power and customer service
  - Maximize opportunities to meet customer needs and improve engagement

3) Business Resiliency

- ❖ Maintain competitiveness and financial performance by utilizing sustainable resources and operational excellence
  - Develop a utility asset management plan
  - Develop financial planning processes that provide fiscal stability, linking service priorities with associated costs
  - Ensure quality, efficiency, and knowledge transfer by documenting standard operating procedures
  - Implement succession plans that ensure continuity of operations
  - Perform an assessment of the organizational structure

4) Technology

- ❖ Optimize technology to meet the evolving business environment
  - Update technology roadmap to guide our technology-related investments and decisions
  - Leverage Advanced Metering Infrastructure (AMI) systems to enhance the customer experience, operations, financial forecasting, and marketing
  - Develop a training plan that supports effective technology adoption, improves utilization, and enables an adaptable workforce

5) Workforce

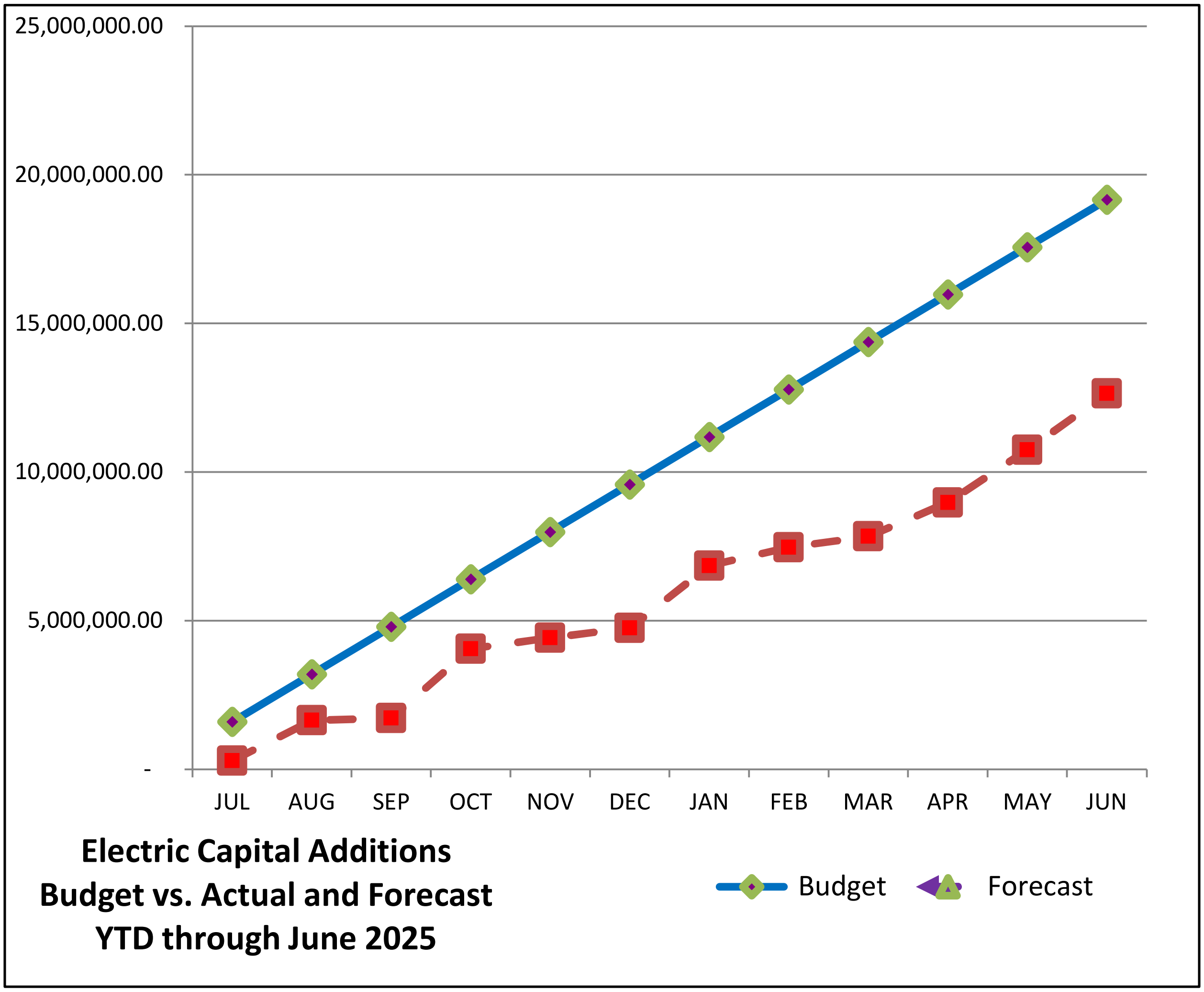
- ❖ Attract and retain employees while fostering a collaborative culture and adapting to changing industry trends
  - Develop a talent outreach plan that highlights the benefits and opportunities of working at AMP to increase talent pool for positions and ensure needed staffing levels
  - Design a training and career development model to enhance employee job satisfaction

AMP has developed KPIs to measure the performance of the utility and has set specific targets for each issue identified. On January 2020, AMP attained 100% clean-energy portfolio and will continue to remain at 100% for future years while maintaining a competitive position.

AMP's rates and fees are intended to recover the actual cost of providing service to each customer, remain competitive with those providing similar services in surrounding communities, and provide a return to the City of Alameda. At its January 2022 meeting, the Board approved a five-year ratemaking policy for FY 2023 through FY 2027. The Board adopted financial guidelines that included a debt service coverage ratio of 1.75 times AMP's total debt service and an operating cash reserve requirement that is at least 145 days for operations during unforeseen events. At its regular meeting conducted April 2025, the Board approved 4.0% in rates for FY 2026. AMP determines the recommended rates based on the results of the 10-year pro forma model, a tool that enables staff to incorporate key assumptions and determine the rate adjustment needed to comply with financial guidelines.

The 10-year pro forma model will continue to be used as a tool to consider yearly adjustments. Additional rate increases could be forecast during these years as key cost drivers, such as rising power and transmission charges, increased operating expenses, and lower load forecasts (translating into lower sales and lower revenue), exert upward pressure on rates. AMP will continue to investigate options to assure that revenues are sufficient to cover the cost of providing quality service to its customers.

In its continuing commitment to provide the most reliable power for Alameda and in support of community development goals, AMP continues to improve its electric distribution network through capital improvements to the supervisory control and data acquisition (SCADA) system and electrical equipment; providing new electric services for residential and business development; providing increased circuit cleansing, maintenance and inspection of high voltage components; upgrading internal systems; as well as a variety of routine enhancements including transformer inspections and meter work.



The Underground Utility District 38 project started construction in June of 2024 and spent nearly $6 million on underground substructures in FY25. Connecting new loads, residential developments in particular, resulted in over $2 million in capital spending. Six vehicles were purchased in FY25 including an All-Electric Boom Truck and a 65' Digger Derrick. The increase in vehicle purchases was largely driven by mechanical issues of vehicles overdue for replacement per the City of Alameda Vehicle Replacement Policy.

AMP aims to maintain reliability comparable to the top quartile of electric utility providers in the Western United States. In FY 2025, AMP achieved significant improvements in reliability metrics, with a 42% reduction in SAIDI and an 81% reduction in SAIFI. This means customers experienced fewer and shorter total outages overall. However, when outages did occur, the average restoration time increased. Because there were fewer large-scale events and smaller, localized outages, there was less opportunity to use system switching to restore service to portions of the load quickly. As a result, many outages required full repair completion before power could be restored

AMP's reliability record is summarized in the chart below:

FY 2025 Reliability Indices

	AMP	APPA benchmark	
	FY 2025	regional avg *	natl. top quartile *
SAIDI [minutes]	24.6	62.78	85
SAIFI [# of outages]	0.15	1.1	0.9
CAIDI [minutes]	163.7	74.11	95

*Based on APPA region 6 and national benchmark study

In addition to the reliable services provided to its customers, AMP has transferred $4.4 million to the City's General Fund in accordance with Measure M approved by voters in November 2016 and paid $1.6 million in Payments-In-Lieu-Of-Taxes (PILOT) and has effectively reduced the tax burden of residents thus improving the quality of life in Alameda while also maintaining rates 47% lower than nearby investment-owned utilities.

Economic Conditions and Outlook

The City of Alameda is an island community characterized by residential neighborhoods, commercial districts, and scenic waterfront views of Oakland, San Francisco, and the greater Bay Area shoreline. The City of Alameda is connected to Oakland by highway links to the north and east and offers ferry service to San Francisco from two terminals.

According to the California Department of Finance, Alameda's population was 79,071 in FY 2025, compared to 78,071 in FY 2024—an increase of approximately 1.2%. The City's unemployment rate rose to 4.7% in FY 2025, up from 3.9% in FY 2024. Alameda's population is expected to continue growing as new housing units are completed and occupied, particularly at the former Naval Air Station (known as Alameda Point) and in other redevelopment areas throughout the City of Alameda.

Alameda's economy supports a diverse mix of public and private sector employers. Major business enterprises include the U.S. Coast Guard Integrated Support Command (transport regulation and administration), the City of Alameda (local government), Bay Ship and Yacht (commercial maritime refit and repair), Marina Village Office Park (real estate management), Penumbra (medical device design and manufacturing), the Alameda Unified School District (public education for more than 9,000 students), San Leandro Hospital and Alameda Health System (health care services), Safeway (retail grocery), and Peet's Coffee (corporate headquarters, roasting, and distribution). Alameda Municipal Power (AMP) provides the electric distribution network that reliably supports this diverse business community and its specialized energy needs.

Overall, the outlook for the City of Alameda is generally stable. Investors continue to demonstrate their faith in the strengths and vitality of the Alameda community with significant capital investments and development throughout the City. AMP continues to recognize trends developing in the marketplace and has adjusted its system expansion budget.

AMP understands that in addition to being responsive to the community, it must assess its risks and plan accordingly. This planning is especially important since operating expenses are expected to escalate as certain power supply contracts expire, renewable energy continues to be prominent in the portfolio, and transmission costs escalate.

Major Initiatives

Community Involvement

Through a wide range of customer programs, community events, partnerships with local agencies and organizations, AMP maintains a strong presence in the community. AMP sponsors a variety of organizations and local events annually and uses multiple communication channels to educate customers about topics such as building electrification, electric vehicles and charging, solar, energy efficiency and sustainability. AMP's customer communications include social media platforms, the AMP website, an email marketing system, and bill insert newsletters, which keep customers informed on important and relevant topics including AMP's programs, services, events, incentives, and rebates.

Major Initiatives in FY 2025

AMP met the community's needs in several ways:

- Launched the Building Electrification Technical Assistance Program, providing technical assistance services to Alameda's non-profit organizations to accomplish their electrification projects.
- Supported 23 community events and programs through sponsorships that totaled $29,400 .
- Co-hosted collaborative social engagement events such as the Home Electrification Fair, and hosted the Alameda Green Homes Tour as well as the Induction Cooking Demo Event.
- Celebrated Public Power Week by volunteering at the Alameda Food Bank, raising funds for the Alameda Women's Shelter and promoting the benefits of public power to Alameda residents.
- Presented a check to the Alameda Education Foundation in the amount of $10,939 for the Power Up for Learning program supporting students STEM programs.

- Processed and distributed $412,073 in rebates over 451 applications to customers that completed electrification and clean transportation efforts.

Economic Development

The City of Alameda and AMP continue to encourage new and existing businesses to develop in Alameda. Alameda's central Bay Area location and strong electric reliability make it an attractive site for energy sensitive enterprises. AMP customers continue to benefit from a strong record of reliability and enjoy electric rates 47% lower than those of nearby cities served by other utilities.

A portion of the east and west ends of Alameda has seen significant growth. During FY 2025, AMP continues to support development at several development hubs in the city. AMP updated its cost methodology for new development service laterals to ensure new developments pay an equitable share for infrastructure costs. AMP continues to work on system enhancements and improvements to better serve customers.

Customer Service

AMP provides a range of customer service options during business hours, allowing customers to obtain billing information, make payments, request or discontinue service, and inquire about programs such as solar rebates and bill assistance. Customers have seven convenient, fee-free payment options, including:

- *Automatic Payment Service (Easy Pay)*
- *Electronic Bill Presentment/Payment (EBPP)*
- *On-line Credit/Debit Card Payment*
- *Credit Card Payments by Phone*
- *U.S. Mail*
- *In-Person Payments*
- *Pay Station*
- *Bill assistance programs*

AMP's website also provides extensive resources, including program information, event listings, rebate details, and access to Public Utilities Board meetings and materials.

Solar & Solar/Battery Rebates and Alternative Fuel Vehicles

AMP continues to support local solar energy production through an income-qualified, residential rebate program and a competitive compensation program for renewable generation customers. Battery electric vehicles are supported by AMP through various means including educational webinars, EV technical assistance services, and generous rebates for used EV's and level 2 EV chargers, both residential and commercial. Additionally, AMP has a Time-of-Use rate specifically to support residential EV charging. AMP continues to provide no cost 24-hour fast charging to the Alameda community via two DCFC charging stations at its service center and AMP's own fleet has 6 light-duty EV sedans and 6 light-duty EV pickup trucks supported by 12 Level 2 EV chargers.

Alameda Point Telephone System

AMP took over the operation of the telephone plant at Alameda Point on July 1, 2000 and converted the operation to a self-sustaining portion of the utility. AMP charges installation and monthly recurring fees to provide for the recovery of maintenance expenses. Capital plant investment for the Alameda Point telephone system has been minimized because the telephone cable pairs to extend telephone services from the AT&T Minimum Point of Entry (MPOE) to tenants leasing space and housing on Alameda Point are temporary. Existing telephone circuits will be abandoned as Alameda Point is redeveloped. In the future, it is expected that a state-certified communications carrier will construct telephone facilities on Alameda Point as part of the overall development plan. Until Alameda Point's redevelopment plans are implemented, the Alameda Point telephone system will continue to support residents, business and economic development by providing access to the public dial telephone network.

Management's Statement of Responsibility

AMP's management is responsible for the integrity and objectivity of all financial data included in this annual report. The statements have been prepared in accordance with accounting principles generally accepted in the United States. The financial data includes amounts that are based on the best estimates and judgments of management.

AMP's management takes seriously its responsibility to establish and maintain an effective internal control system. It employs a variety of administrative and accounting processes that form its internal control system. The controls provide reasonable, rather than absolute assurance, that the financial statements are free of any material misstatements because internal control costs should not exceed the benefits derived. Management periodically reviews the internal control system. Actions are taken to correct deficiencies as they are identified. AMP maintains high standards in selecting, training, and developing personnel to assure that its operations are conducted in conformity with applicable laws and is committed to maintaining programs to encourage and assess compliance with the highest standards of personal and business conduct.

Independent Audit

California State statutes and the City of Alameda's charter require an annual audit of AMP's financial records and transactions. Maze and Associates, a certified public accounting firm, is contracted to independently audit the financial information of AMP. Maze was provided access to all information and documentation necessary for the audit. The financial section of the Annual Comprehensive Financial Report (ACFR) contains the Independent Auditor's Report as well as management's discussion and analysis of the financial data, the financial statements, and the notes to the financial statements. In the normal course of work, the independent auditor may recommend changes in control procedures and AMP's management will take appropriate action on such recommendations.

Award

The Government Finance Officers Association (GFOA) of the United States and Canada awarded a Certificate of Achievement for Excellence in Financial Reporting to AMP for its Annual Comprehensive Financial Report (ACFR) for the fiscal year ended June 30, 2024. A GFOA Certificate of Achievement is valid for a period of 1 year. This was the twenty-eighth consecutive year that AMP has achieved this prestigious award. In order to be awarded a Certificate of Achievement, a government unit must publish an easily readable and efficiently organized annual comprehensive financial report that satisfies both generally accepted accounting principles and applicable legal requirements.

AMP believes that its current Annual Comprehensive Financial Report will continue to meet the Certificate of Achievement Program's requirements and will be submitting it to the GFOA to determine its eligibility for another Certificate of Achievement for Excellence in Financial Reporting from GFOA.

Acknowledgments

This report is the culmination of the hard work and dedication of many AMP employees and the independent auditor, Maze and Associates. AMP staff would like to acknowledge the support of the Board for its continuing direction and oversight in providing value to the Alameda community.

Respectfully submitted,

Timothy Haines

Timothy Haines
General Manager

Principal Officers

PUBLIC UTILITIES BOARD

Christina McKenna, President

Elise Hunter, Vice President

Ryan Bird, Commissioner

Nick de Vries, Commissioner

Jennifer Ott, City Manager

GENERAL MANAGER

Timothy Haines

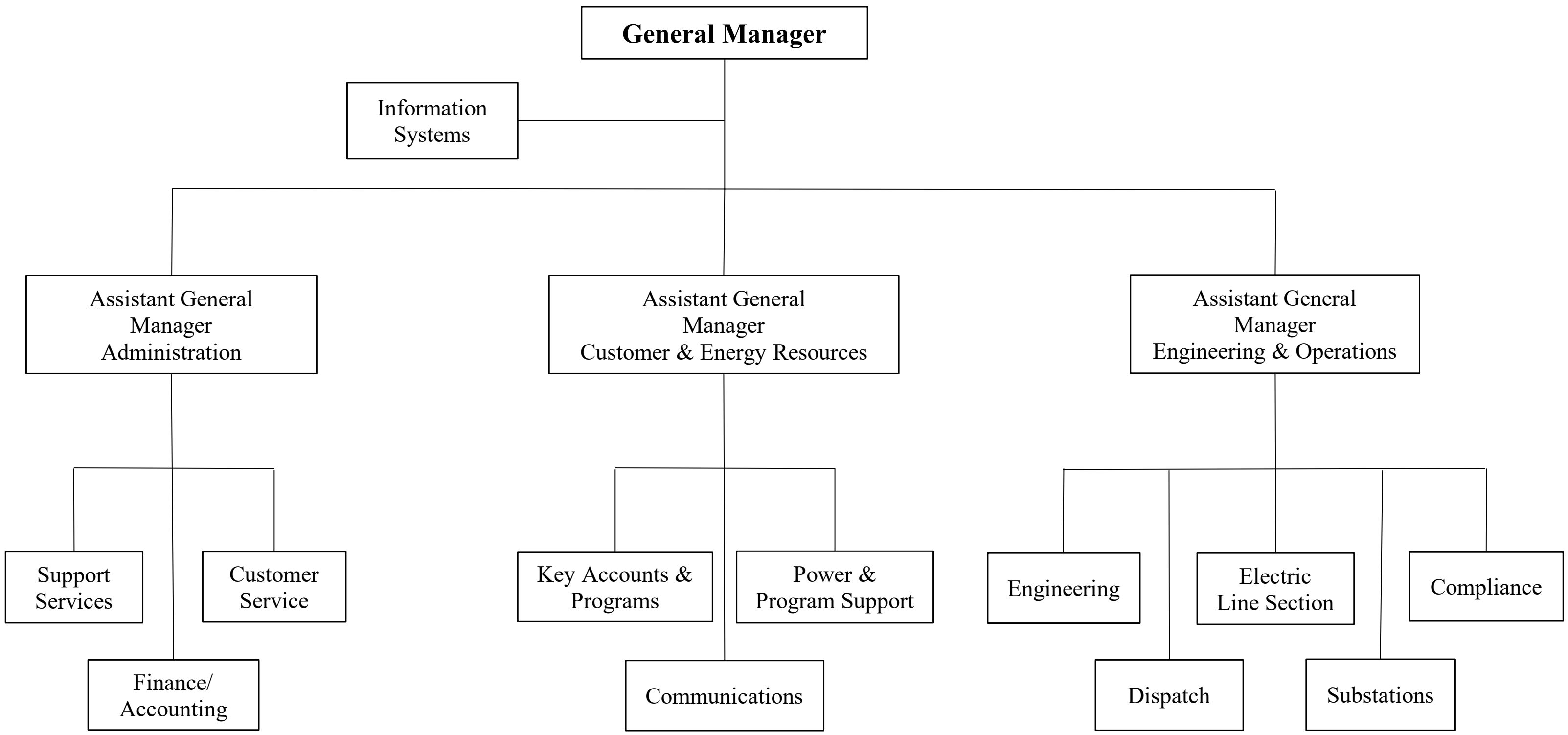
MANAGERS

Teri Dean Alderson, Assistant General Manager – Administration

Alan Harbottle, Interim Assistant General Manager – Engineering & Operations

Chris Ferrara, Assistant General Manager – Customer & Energy Resources

City of Alameda
Alameda Municipal Power
Organizational Chart



Government Finance Officers Association

Certificate of Achievement for Excellence in Financial Reporting

Presented to

Alameda Municipal Power
California

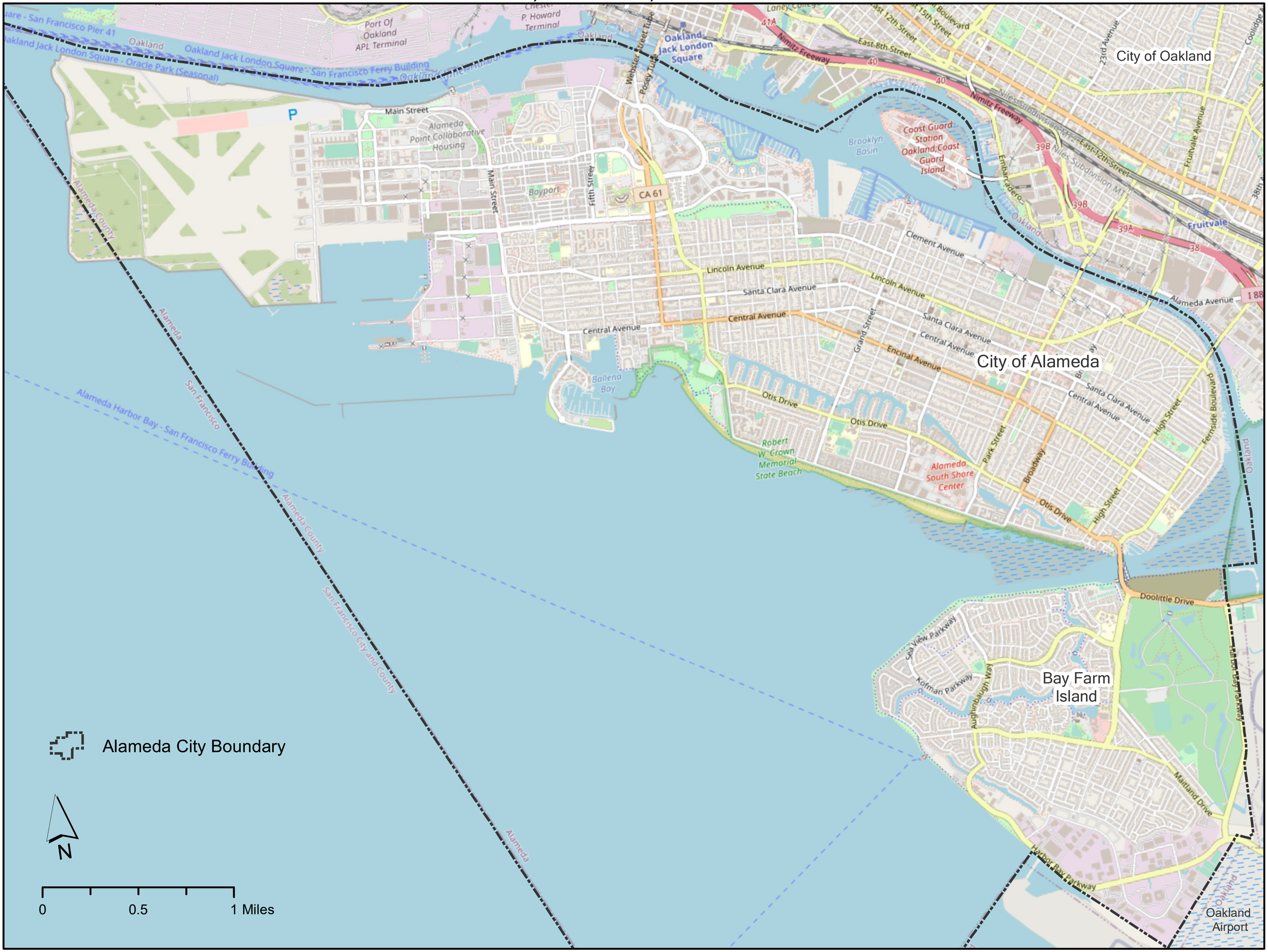
For its Annual Comprehensive
Financial Report
For the Fiscal Year Ended

June 30, 2024

Christopher P. Morrill

Executive Director/CEO

Alameda, California, United States



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Financial Section

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INDEPENDENT AUDITORS' REPORT

To the Public Utilities Board
Alameda Municipal Power
Alameda, California

Report on the Audit of the Financial Statements

Opinions

We have audited the accompanying financial statements of business-type activities of Alameda Municipal Power (AMP), an enterprise fund and department of the City of Alameda, California, as of and for the years ended June 30, 2025 and 2024, and the related notes to the financial statements, which collectively comprise AMP's basic financial statements as listed in the Table of Contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities of AMP as of June 30, 2025 and 2024, and the respective changes in its financial position and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinions

We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of AMP and to meet our other ethical responsibilities, in accordance with the relevant ethical requirement relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about AMP's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

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Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with generally accepted auditing standards and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with generally accepted auditing standards and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of AMP's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about AMP's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis and other Required Supplementary Information as listed in the Table of Contents be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board, who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the Introductory Section and Statistical Section listed in the Table of Contents, but does not include the basic financial statements and our auditor's report thereon. Our opinions on the basic financial statements do not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated December 4, 2025, on our consideration of AMP's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of AMP's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering AMP's internal control over financial reporting and compliance.

Maze + Associates

Pleasant Hill, California
December 4, 2025

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As management of Alameda Municipal Power (AMP), we offer readers of AMP's financial statements this narrative overview and analysis of the financial activities of AMP for the year ended June 30, 2025. Readers are encouraged to consider the information presented here in conjunction with information contained in the preceding transmittal letter, the accompanying financial statements and notes, the statistical section of the Annual Comprehensive Financial Report (ACFR) and the bond disclosure information.

FINANCIAL STATEMENTS OVERVIEW

The basic financial statements present the financial picture of AMP from an economic resources measurement focus using the accrual basis of accounting similar to a private-sector business.

The Statement of Net Position presents information on AMP's assets, deferred outflows/inflows, and liabilities with the difference reported as net position. The primary purpose of this Statement is to provide relevant information about AMP's assets, liabilities, deferred outflows/inflows, net position, and their relationships to each other at the year-end closing date. The information provided in the Statement, used with related disclosures and information in other financial statements, helps the public, creditors, and others assess AMP's ability to continue to provide services, understand its liquidity, financial flexibility, and its ability to meet obligations.

The Statement of Revenues, Expenses and Change in Net Position present relevant information showing how AMP's resources were used in providing services and how AMP's net position changed during the period. The information helps the public, creditors, and others to evaluate the organization's performance. The Statement allows the reader to assess AMP's service efforts, its ability to continue to provide services, the results of management's stewardship, and other aspects of performance.

The Statement of Cash Flows presents relevant information about cash receipts and payments and the net change in cash resulting from AMP's operating, investing, and financing activities during the period. The Statement provides information for investors, creditors, and others, to evaluate AMP's financial position, its ability to generate future cash flows, its ability to pay bills and meet obligations, and the differences between net income and net cash provided (used) by AMP's operating, investing, and financing activities during the period.

FINANCIAL HIGHLIGHTS

- AMP's total net position increased by $8.3 million for the year ended June 30, 2025 while last year an increase of $3.7 million was reported.
- The increase of $8.3 million to the total net position comes from a combination of factors including:
  - Current Assets increased by $15 million for the year ended June 30, 2025 while last year's current assets increased by $10.2 million. The change in current assets from end of FY 2024 to FY 2025 was mainly driven by increased cash & cash equivalent of $11.8 million (see Analysis of Combined Cash Flows) and increased investments of $2.9 million. Last year's change in current assets was mainly driven by increased cash & cash equivalent of $4.7 million, increased investments of $2.8 million due to earned interest and increase in fair market value, and increased inventory purchases of $1.6 million for capital expenditures and operations.

  - Capital Assets net of depreciation increased $7 million for the year ended June 30, 2025, while last year's increase was $257K (see note 3 for additional information regarding capital assets and depreciation amounts).
  - Other Non-current Assets decreased by $2.2 million for the year ended June 30, 2025 while last year an increase of $1 million was reported. Current year change was primarily due to a $4 million decrease in investments designated for special purposes including $4.4 million decrease in the Underground Special Fund (see note 2 for additional information regarding AMP's Designated Investments). Previous year change was primarily due to a $960K increase in AMP's share in NCPA projects and reserve (see note 8 for additional information regarding AMP's share in NCPA projects and reserve).
  - Deferred Outflow of Resources decreased by $2.3 million for the year ended June 30, 2025, while last year was reported as a decrease of $1.9 million.
  - Current Liabilities increased by $2.8 million for the year ended June 30, 2025 due to $1.8 million higher accrued expenses, while last year an increase of $1.5 million was reported mainly due to $1.4 million higher accrued expenses.
  - Non-current Liabilities decreased by $4.1 million for the year ended June 30, 2025, while last year a decrease of $1.3 million was reported. The current change was primarily due to a decrease in long term debt, net of current portion, of $1.9 million (see note 4 for additional information) and decrease in net pension liability of $1.5 million. Last year's change was primarily due to a decrease in long term debt, net of current portion, of $1.8 million. This decrease was offset by a $562K increase in net pension liability
  - Deferred Inflow of Resources increased $10.6 million for the year ended June 30, 2025, primarily as a result of a $10 million increase in the balancing account. Last year Deferred Inflow of Resources increased $5.7 million as a result of a $6.1 million increase in the balancing account.

- Operating revenue increased $3.8 million for the year ended June 30, 2025 while last year had an increase of $5.2 million. Electricity sales revenue increased $4.2 million in FY 2025 while last year electric sales revenue increased by $3.9 million.
- Excluding purchased power, depreciation and the balancing account, electric fund operating expenses for the year ended June 30, 2025 increased slightly by $51K while last year had an increase of $4.2 million. Prior year's significant increase was mainly due to general and administration costs increase of $2.2 million from higher pension expense & liability insurance, and operations & maintenance increase of $2 million mainly due to increased transformer repairs, poles maintenance and tree trimming for preventative purposes.
- Purchased power expenses decreased $3.3 million for the year ended June 30, 2025, while last year a $405K decrease was reported.
- Depreciation and amortization expense increased $296K for the year ended June 30, 2025, while last year a $111K increase was reported.
- The balancing account, which is used to stabilize rates, increased by $3.9 million, while last year it increased by $838K (see note 1C for additional information on the deferred inflows of resources related to balancing account).

- Electric fund non-operating revenues/expenses had a net increase of $1.9 million in revenues for the year ended June 30, 2025 while last year a net increase in spending of $5.1M was reported.
  - Fair value of NCPA Projects and Reserves increased by $1.1 million during the year ended June 30, 2025, while last year a decrease of $24K was reported.
  - Interest income was higher by $367K for the year ended June 30, 2025 while last year's increase was $1.4 million as a result of higher interest rates and change in fair market value that impacted several investments and called notes. Interest expense was lower by $127K for the year ended June 30, 2025 while last year interest expense was lower by $119K.
  - Fair market value adjustment increased by $175K during the year ended June 30, 2025, while last year an increase of $1 million was reported.

- AMP continued its support of the City's general fund with a voter approved contribution of $4.5 million in FY 2025 and $4.4 million in FY 2024.

- Cash and equivalents increased $11.8 million for the year ended June 30, 2025 while last year an increase of $4.7 million was reported. The results come from a combination of factors including:
  - Net cash provided by operating activities increased $9.0 million for year ended June 30, 2025 and an increase of $4.4 million for year ended June 30, 2024 was reported. Customer receipts increased $5.6 million in FY 2025, while an increase of $4.7 million was reported last year. Supplier payments decreased $999K while prior year saw a decrease of $1.7 million. Employee payments decreased $2.8 million in FY 2025, while an increase of $3.3 million was recognized in FY 2024.
  - Net cash used for non-capital financing activities increased $162K for year ended June 30, 2025 while last year an increase of $122K was reported, both as a result in the net change for City transfers and Pilot charges which are based on the CPI index.
  - Net cash used for capital and related financing activities increased $6.9M while last year it was reported that net cash used in capital and related financing activities increased $325K.
  - Net cash proceeds from investing activities increased $5.1 million in FY 2025 while last year it was reported that net cash used for investing activities increased $2.9 million. The increase from FY 2025 is mainly due to $3.8 million higher proceeds from investments designated for special purposes and $702K higher proceeds from sale or maturity of unrestricted investments, net purchases. In FY 2024, proceeds from unrestricted investments and investments designated for special purposes increased $9.1 million from FY 2023. This increase was offset by $1.4 million less interest receipts and $5.4 million increase in purchases of unrestricted investments compared to FY 2023.

COMBINED NET POSITION

AMP's Combined Net Position as of June 30:

(Dollars in thousands)

	2025	2024	2023
Assets:			
Current Assets	$ 107,154	$ 92,113	$ 81,898
Capital Assets, net of depreciation	43,021	36,067	35,810
Other Non-current Assets	45,574	47,812	46,784
Total Assets	**195,749**	**175,991**	**164,491**
Deferred Outflow of Resources	**5,227**	**7,496**	**9,358**
Liabilities:			
Current Liabilities	16,546	13,776	12,253
Non-current Liabilities	39,802	43,901	45,240
Total Liabilities	**56,348**	**57,677**	**57,493**
Deferred Inflow of Resources	**58,871**	**48,320**	**42,584**
Net Position			
Net Investment in Capital Assets	27,673	18,678	15,877
Restricted	5,441	5,259	5,046
Unrestricted	52,644	53,555	52,848
Total Net Position	**$ 85,758**	**$ 77,491**	**$ 73,772**

ANALYSIS OF NET POSITION

AMP's combined total net position was $85.8 million as of June 30, 2025, and was $77.5 million as of June 30, 2024. This year's combined total net position increased by $8.3 million , or 10.7% of last year, and last year's combined total net position increased $3.7 million, or 5% of the combined total net position as of June 30, 2023.

The largest portion of combined total net position is the cash and cash equivalents and investments. The next largest portion is the unrestricted Net Position reserve accounts. AMP's board may designate how these funds are expended. The third largest contributor to AMP's combined total net position is net investment in capital assets (e.g., land, utility plant, buildings, vehicles and equipment) less any related debt still outstanding that was used to acquire those assets. The capital assets are used to provide electric services and, consequently, are not available for future spending. Although AMP's investment in capital assets is reported net of related debt, it should be noted that the resources to repay this debt must be provided from net revenues of the electric fund. The capital assets themselves cannot be used to liquidate these liabilities except under extraordinary circumstances.

The largest portion of combined total liabilities is used to finance AMP's operations, construction, and NCPA activities. Total combined assets increased $19.8 million (11.2% increase) from year ended FY 2024 to year ended FY 2025, while the total combined assets increased $11.5 million (7% increase) from year ended FY 2023 to year ended FY 2024 . Total combined Deferred Outflow of Resources decreased $2.3 million (30.3% decrease) from year ended FY 2024 to year ended FY 2025, while combined Deferred Outflow of Resources decreased $1.9 million (19.9% decrease) from year ended FY 2023 to year ended FY 2024. Deferred Inflow of Resources increased $10.6 million (21.8% increase) to last year's total relating to pensions, OPEB, and the balancing account while Deferred Inflow of Resources increased $5.7 million ($13.5% increase) from year ended FY 2023 to last year. Total combined liabilities decreased by $1.3 million (2.3% decrease) compared to last year's total, while last year's total increased by $184K (0.3% increase) compared to year ended June 30, 2023.

Combined Statement of Revenues, Expenses and Changes in Net Position as of June 30:

(Dollars in thousands)

	2025	2024	2023
Operating Revenues			
Electric Sales	$ 76,526	$ 72,284	$ 68,414
Other Services Revenue	5,395	5,843	4,556
Total Operating Revenues	81,921	78,127	72,971
Operating Expenses			
Purchased Power	32,416	35,697	36,102
Energy Efficiency, Solar, Other	1,317	1,637	1,401
Operations and Maintenance	9,831	8,104	6,125
Customer Accounts, Information Systems	3,407	3,114	3,179
Administrative and General	10,798	11,855	9,642
Depreciation and Amortization	3,632	3,336	3,225
Sales Expense	481	400	410
Jobbing Sales Expense	1,203	1,875	1,986
Balancing Account	10,038	6,116	5,278
Total Operating Expenses	73,122	72,134	67,347
Operating Income (Loss)			
Electric	8,799	5,993	5,624
Telecommunications	-	-	-
Total Operating Income (Loss)	8,799	5,993	5,624
Non-operating Revenue (Expense)			
Interest Income on Investments	5,220	4,678	1,696
Interest Expense	(852)	(979)	(1,098)
Gain (Loss) from Sale of Capital Assets	71	-	-
Other Expense	(10)	(3)	(4)
Increase (Decrease) in Value of NCPA Projects	1,146	(24)	(2,033)
Alameda Point Phone Maintenance-Net	34	35	43
Misc Non-operating Income (Expense)	25	21	17
Telecommunications			
Payment In-lieu of Taxes	(1,652)	(1,621)	(1,588)
Total Non-Operating Revenue (Expense)	3,981	2,108	(2,967)
Income (Loss) Before Transfers and Special Item	12,780	8,101	2,656
Transfers in (to Telecom)			
Transfer to City of Alameda	(4,513)	(4,382)	(4,293)
Transfers out (from Electric)			
Total Transfers	(4,513)	(4,382)	(4,293)
Change in Net Position			
Electric	8,267	3,719	(1,636)
Telecommunications			
Total Change In Net Position	**$ 8,267**	**$ 3,719**	**$ (1,636)**

ANALYSIS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

Changes in Net Position

Electric net position increased $8.3 million for the year ended June 30, 2025 while last year an increase of $3.7 million was reported. Operating revenues were higher than prior year by $3.8 million, while prior year was higher than fiscal year ended June 30, 2023 by $5.2 million. Operating expenses increased $989K from prior year due to higher operations and maintenance costs mainly related to increased tree trimming expenses for preventative purposes, while prior year was higher than FY 2023 by $4.8 million mainly due to the increase in pension liability, increase in operation maintenance expense, and increase in new building electrification/EV charger rebate programs. Non-operating revenue increased from prior year by $1.9 million mainly due to a $1.2 million increase in value of the NCPA projects, compared to a $5.1 million increase in non-operating revenue from FY 2023 to prior year. The $5.1 million increase was mainly due to the change in the value of the NCPA projects ($23.8K decrease in FY 2024 vs $2M decrease in FY 2023), increased interest income on unrestricted investments of $1.3 million, and $1.6 million increase in fair market value of investments.

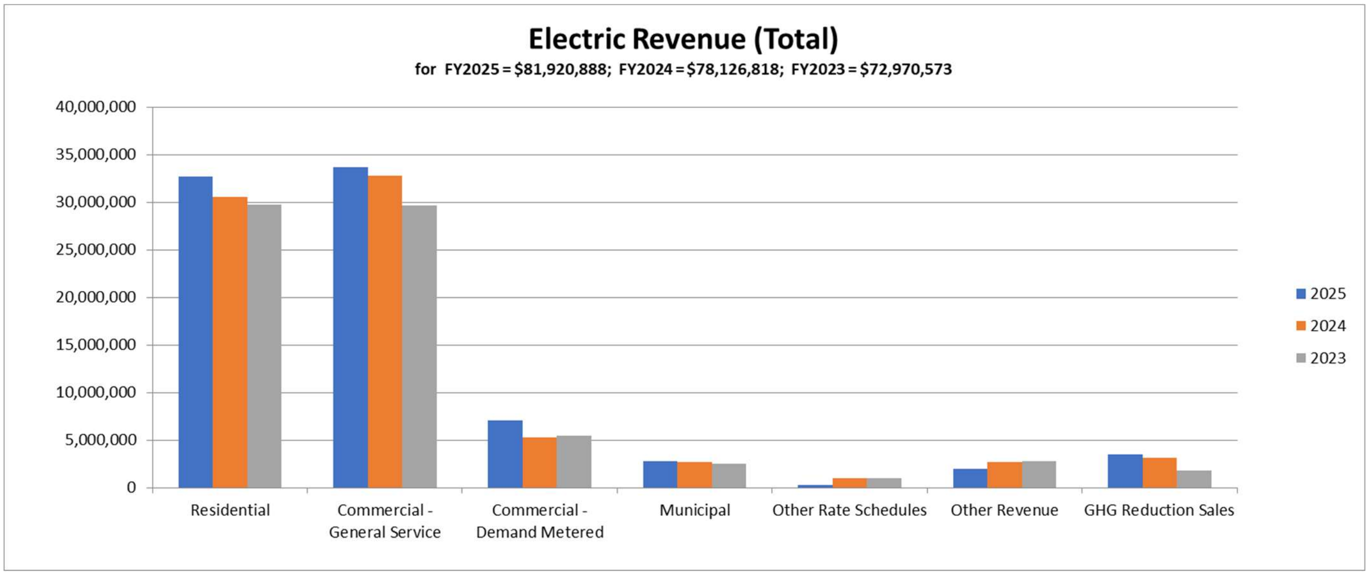
Condensed Statement of Changes in Net Position as of June 30:

(Dollars in thousands)

	2025	2024	2023
Operating Revenues	$ 81,921	$ 78,127	$ 72,971
Operating Expenses	73,122	72,134	67,347
Operating Income	8,799	5,993	5,624
Total Non-operating Revenue (Expense)	3,981	2,108	(2,967)
Transfers Out	(4,513)	(4,382)	(4,293)
Change In Net Position	$ 8,267	$ 3,719	$ (1,636)

Operating Revenues

Electric operating revenue increased by $3.8 million while last year an increase of $5.2 million was reported. Electricity sales revenue in FY 2025 increased by $4.2 million, trade revenue increase of $279K, offset by jobbing sales decrease of $671K. Electricity sales revenue in FY 2024 increased by $3.9 million, trade revenue increase of $1.4 million, offset by jobbing sales decrease of $111K.



Sources of Electric Revenue

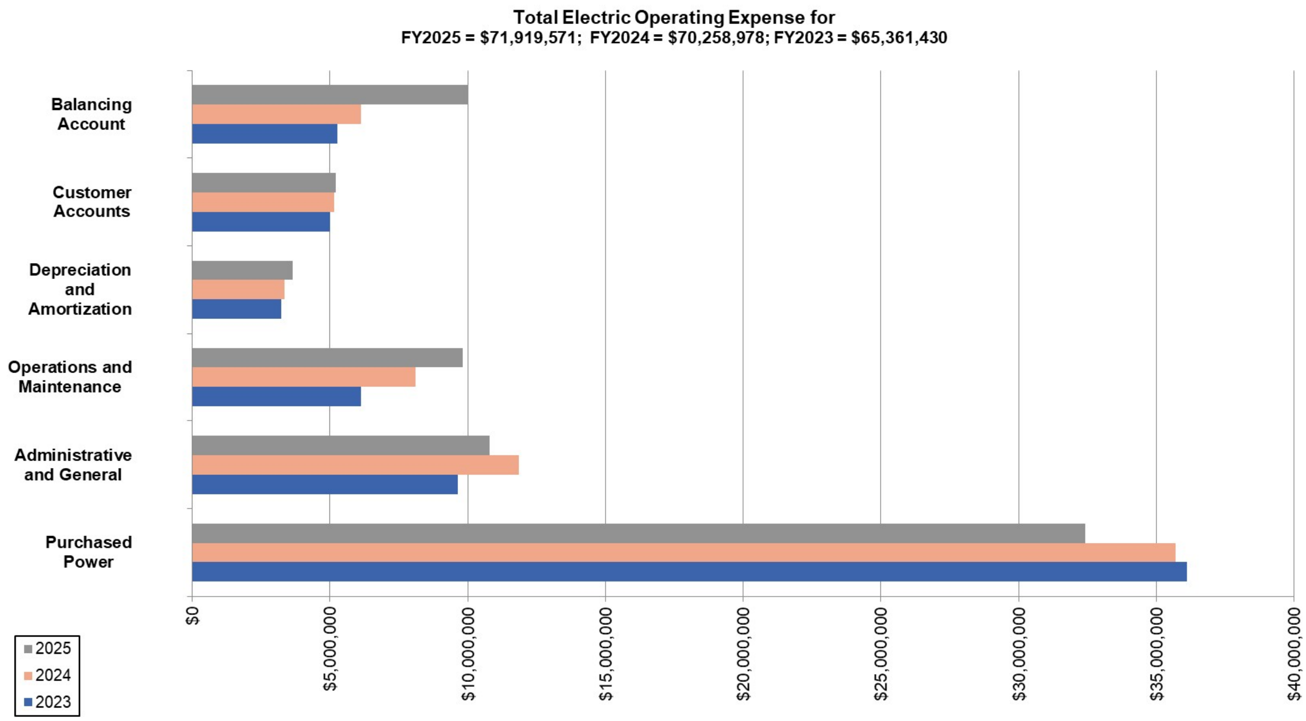
AMP's operating revenues are based on rate schedules authorized by the Board. Such rates are designed to recover AMP's cost of service and still be competitive with those in surrounding areas. Rates also provide a contribution to the City of Alameda; voters approved the contribution amount in November 2016.

Operating Expenses

Operating expenses, excluding the adjustment for balancing account accumulation, were lower than last year's results by $2.9 million mainly due to a $3.3 million decrease in purchased power. In FY 2024, a $3.9 million increase in operating expenses was reported due to higher administrative and general expenses of $2.2 million due to higher pension expense, and higher operations & maintenance of $2 million due to increased transformer repairs, poles maintenance and tree trimming for preventative purposes compared to FY 2023.

The Balancing Account is used by AMP to stabilize rates by accumulating differences between the actual costs of providing service with the related revenues designated for recovery of such costs.

AMP continues to experience volatility in California energy markets as seasonal weather impacts hydroelectric generation, natural-gas prices impact peak-demand electricity prices, geothermal generation is impacted by aging facilities, new landfill-gas generation becomes operational and new state laws and regulations are implemented for GHG reduction strategies. Although AMP recognizes that energy markets have stabilized since the energy crisis of 2000-2001, it is keenly aware that adverse energy markets may return due to a variety of factors that affect both the supply of and demand for electric energy in the Western United States.



Non-Operating Revenues (Expenses)

Non-operating revenue increased by $1.9 million from prior year mainly due to a $1.2 million increase in value of NCPA projects and $367K increase in interest income on investments. In prior year, a $5.1 million increase in non-operating revenue was reported mainly due to return on investment revenues were $3 million higher in FY 2024 than FY 2023 as a result of higher interest income on investments and change in fair market value, and expense from the value of NCPA projects & reserve significantly decreased by $2 million from FY 2023.

ANALYSIS OF COMBINED CASH FLOWS

Net Change in Cash and Equivalents

Combined net change in cash and equivalents increased by $11.8 million for the year ended June 30, 2025 while last year an increase of $4.7 million was reported. AMP generates cash from its electric operations or utilizes its reserves to meet its operating needs including payments in lieu of taxes (PILOT), return on investment (ROI), and transfer to the City's General Fund. AMP places Cap & Trade net revenues, GHG sales revenues, and Low carbon fuel standards sales revenues into investments for the Board designated special reserves for those funds. Changes in the cash flows are mainly due to improved customer receipts relating to rate adjustments, increased proceeds from sale or maturity of investments, offset by increased capital assets purchases.

Combined Condensed Statement of Cash Flows as of June 30:

(Dollars in thousands)

	2025	2024	2023
Operating Activities	$ 25,671	$ 16,679	$ 12,253
Non-capital Financing Activities	(6,165)	(6,003)	(5,881)
Capital and Related Financing Activities	(13,244)	(6,339)	(6,014)
Investing Activities	5,522	401	(2,482)
Net increase (decrease) in cash and cash equivalents	$ 11,785	$ 4,738	$ (2,123)

Cash Flows from Operating Activities

Cash from operating activities increased $9.0 million for the year ended June 30, 2025 while last year increased $4.4 million. Customer receipts increased $5.6 million in FY 2025, compared to a $4.7 million increase in FY 2024, both as a result of rate increases. Payments to employees in FY 2025 decreased $2.8 million mainly due to vacancies during the current fiscal year, while an increase of $3.3 million was reported last year due to increase in pension expense. Payments to suppliers decreased $999K in FY 2025, while a decrease of $1.7 million last year was reported mainly due to purchased power.

Cash Flows from Non-Capital Financing Activities

Cash flows from noncapital financing consisted of the transfer to the City and payments in lieu of taxes which were consistent with prior year and increase by the CPI on an annual basis. Payment in lieu of taxes is capped at 2% or CPI whichever is greater.

Cash Flows from Capital and Related Financing Activities

Cash flows used for capital and related financing activities increased $6.9 million compared to a $325K increase prior year. Current year increase in capital and related financing activities is mainly due to a $7 million increase in capital purchases.

During FY 2025, AMP's capital asset additions for the electric system were $10.6 million compared to $3.6 million last year. AMP's capital asset additions for the electric system included projects to expand, replace, and enhance facilities, to improve their efficiency and reliability, to extend their useful life, to comply with laws and regulations, and/or to meet the increasing demands on the electric system. During FY 2025 specific capital purchases that occurred include continued construction of the Underground Utility District 38 Project, six vehicles purchased including an All-Electric Boom Truck and 65' Digger Derrick, and the start of switchgear bottle replacements at the Cartwright substation. Specific capital purchases that occurred during FY 2024 include a Cable handler, Cayenta Upgrade, Security Camera System, and the start of construction of the Underground Utility District 38 Project.

Cash Flows from Investing Activities

Cash flows net proceeds from Investing activities increased $5.1 million compared to a $2.9 million increase prior year. The increase from FY 2025 is mainly due to $3.8 million higher proceeds from investments designated for special purposes and $702K higher proceeds from sale or maturity of unrestricted investments, net purchases. In FY 2024, proceeds from sale or maturity of unrestricted investments increased by $9 million from last year, offset by a $1.4 million decrease in interest receipts and $5.4 million increase in purchase of unrestricted investments.

ANALYSIS OF LONG-TERM DEBT

On August 4, 2010, AMP authorized the issuance of $8.7 million in Revenue Bonds, Series 2010A, and $22.99 million in taxable Revenue Bonds, Series 2010B. Proceeds were used to prepay the outstanding Electric System Revenue Series 2000A COPs and the Series 2000AT taxable COPs, to fund a security deposit for the 2010A/B bonds, and to pay the cost of issuance for the 2010 A/B bonds. The maturity date for the Series 2010A is July 1, 2030 and the maturity date for the Series 2010B is July 1, 2027. The reader is encouraged to read Note 4, and the statistical section of this report, for additional information regarding long-term debt and expected payments for this bond. We did not require any additional long-term borrowing to meet our objectives this year.

Long-Term Debt as of June 30:

(Dollars in thousands)

	2025	2024	2023
Revenue Bonds, Series 2010A	$ 8,700	$ 8,700	$ 8,700
Taxable Revenue Bonds, Series 2010B	4,740	6,555	8,260
Long-Term Debt	$ 13,440	$ 15,255	$ 16,960

ANALYSIS OF LEASE LIABILITY

In March 2016, AMP entered into a property lease agreement with the 1835 Alameda Property, LLC for warehousing/distributing space. The lease terms for the agreement started on May 1, 2016 and will expire on April 30, 2031. The base rent is $24,700 per month. The monthly lease payments are increased annually in the amount of 3% every May 1. The reader is encouraged to read Note 11B for additional information regarding AMP's lease agreement with 1835 Alameda Property, LLC.

Lease Liability as of June 30:

(Dollars in thousands)

	2025	2024	2023
Lease liability (non-current portion)	$ 1,792	$ 288	$ 269
Lease liability (current portion)	308	2,100	2,388
Lease Liability - 1835 Alameda Property, LLC	$ 2,100	$ 2,388	$ 2,657

ANALYSIS OF CAPITAL ASSETS

AMP's investment in capital assets for its electric operations amounts to $43 million, net of accumulated depreciation. The investment in capital assets includes land, buildings, construction-in-progress, electric utility plant, machinery and equipment, transportation, and computer equipment. Readers desiring more detailed information on capital asset activity should see Note 3 and information in the Statistical Section of this report.

Electric Capital Assets as of June 30:

(Dollars in thousands)

	2025	2024	2023
Land and Rights	$ 220	$ 220	$ 220
Construction In Progress	13,913	7,700	6,316
Utility Plant	94,864	92,066	90,818
Service Center Building	8,168	8,168	8,168
Machinery & Equipment	10,095	10,118	9,952
Transportation Equipment	4,220	4,536	4,299
Computer Equipment	5,113	5,252	4,695
Furniture & Fixtures	978	980	980
Oak Warehouse-Capital Lease	3,143	3,143	3,143
Less Accum Amortization-Capital Lease	(1,278)	(959)	(639)
Less Accum Depreciation	(96,414)	(95,158)	(92,142)
Capital Assets, Net	**$ 43,021**	**$ 36,067**	**$ 35,810**

ANALYSIS OF ECONOMIC FACTORS

Economic Factors and Next Year's Budget

AMP's financial outlook for FY 2026 reflects continued operational stability, strengthened liquidity, and a sustained commitment to long-term financial planning. FY 2025 closed with an $8.3 million increase in net position, an $11.8 million increase in cash and cash equivalents, and a $10 million increase in the balancing account. These results position AMP to manage cost pressures, fund capital priorities, and maintain rates that are both stable and predictable for customers.

AMP continues to use its 10-year pro-forma, Board-established financial guidelines, and reserve policies to guide long-range planning. This framework supports the annual budget process and ensures that AMP is able to balance operational needs, regulatory requirements, and customer expectations. For FY 2026, the adopted budget anticipates electric operating revenues of $88.7 million, reflecting the approved four-percent rate adjustment. The FY 2026 budget incorporates higher procurement and operating costs, including an estimated $1.3 million increase in purchased power relative to the original FY 2025 budget, as well as higher labor, service, and material costs.

Excluding purchased power, FY 2026 operating expenses total $37.7 million, an increase of 22.8 percent from FY 2025. This increase is driven primarily by expected growth in operations and maintenance activities, rising labor and benefit costs, and expanded customer and program offerings aligned with AMP's strategic priorities. The FY 2026 non-operating budget is projected to decrease by $941,000 and includes funding for outside billing projects, debt service, PILOT/ROI obligations, and a $4.6 million transfer to the City of Alameda as authorized by voters. No additional long-term debt is anticipated in FY 2026.

AMP's FY 2026 capital program totals $27.8 million and includes continued investment in undergrounding projects, system reliability upgrades, new load additions, long-lead inventory, and ongoing substation improvements. These projects address infrastructure aging, system resilience, and customer growth.

Based on current projections, operating revenues in FY 2026 are expected to meet operating needs. Special reserves will continue to be used to supplement capital investments as necessary, and working capital will serve as a buffer for timing differences between revenues and expenditures. AMP will continue prioritizing small, consistent annual rate adjustments to reduce volatility and maintain customer affordability while supporting long-term financial stability.

Market Risk

Each year during budget development, AMP considers the risk exposure that it faces. The risk exposure can be categorized into broad categories including power supply risks, credit risks, other supply-based risks, demand side risks, legislative / regulatory risks, and other utility risks. AMP manages energy price risks through its involvement with NCPA and their energy commodity risk management policies, processes, and procedures to help mitigate fluctuations in energy prices. NCPA also monitors and manages credit risk with its trading counter parties. In addition to policies, processes and procedures, AMP manages its risk exposure by maintaining adequate reserves and establishing new reserves as needed. AMP is exposed to changes in interest rates primarily because of its borrowing and investing activities used for liquidity purposes and to fund business operations as well as finance capital expenditures.

AMP's investment policy limits investments to financial instruments that maximize the safety of principal (See Note 2 to the Basic Financial Statements). In addition, AMP has restricted investments invested in accordance with guidelines established in the related bond documents.

Each year during budget development, AMP evaluates the various risks that may affect its financial position and operations. These risks generally fall into several broad categories, including power supply risk, credit and counterparty risk, supply-based and commodity risks, demand-side variability, legislative and regulatory changes, and other operational risks inherent to a public electric utility.

AMP manages energy price and supply risk through its participation in the Northern California Power Agency (NCPA). NCPA implements established energy commodity risk-management policies, procedures, and controls designed to mitigate exposure to fluctuations in energy prices and to strengthen portfolio stability. NCPA also monitors and manages credit exposure to trading counterparties to reduce the risk of financial loss.

In addition to these formal risk-management processes, AMP actively manages its overall financial risk by maintaining adequate reserves and establishing designated reserves when needed. The balancing account continues to serve as a key financial tool to absorb short-term volatility between actual power supply costs and revenues collected through rates. AMP is also exposed to interest-rate risk related to both borrowing and investing activities used to support liquidity, operational needs, and capital investments.

AMP's investment policy emphasizes the safety of principal and compliance with state law, while maintaining sufficient liquidity to meet operational requirements (see Note 2 to the Basic Financial Statements). Restricted investments are held in accordance with guidelines established in applicable bond documents.

REQUESTS FOR INFORMATION

This financial report is designed to provide the Board, Alameda citizens, taxpayers, creditors, and investors with a general overview of AMP's finances. Questions concerning any of the information provided in this report or requests for additional information should be addressed to Alameda Municipal Power; Assistant General Manager - Administration; 2000 Grand Street; Alameda, California 94501.

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Alameda Municipal Power
Electric Enterprise Fund
Statements of Net Position (Continued)
June 30, 2025 and 2024

ASSETS	2025	2024
CURRENT ASSETS		
Cash and cash equivalents (Note 2)	$51,946,078	$40,161,267
Investments (Note 2)	37,477,312	34,598,854
Interest receivable	790,146	763,105
Accounts receivable, net	8,558,603	9,138,356
Materials and supplies	8,330,763	7,411,184
Prepaid and other	50,687	40,000
Total current assets	107,153,589	92,112,766
NON-CURRENT ASSETS		
Capital assets (Note 3):		
Nondepreciable	14,133,355	7,919,827
Depreciable	126,580,493	124,264,205
Accumulated Depreciation	(97,692,690)	(96,117,172)
Total capital assets, net	43,021,158	36,066,860
Restricted investments (Note 2)	5,440,578	5,258,532
Investments designated for special purposes (Note 2)	31,386,625	35,362,198
Investments in Joint Venture -		
Share of certain NCPA projects and reserves (Note 8)	8,747,196	7,191,054
Total non-current assets	88,595,557	83,878,644
TOTAL ASSETS	195,749,146	175,991,410
DEFERRED OUTFLOWS OF RESOURCES		
Deferred amount on refunding	191,891	253,542
Pension related (Note 6)	4,912,184	7,158,222
OPEB related (Note 7)	123,227	84,017
Total deferred outflows of resources	5,227,302	7,495,781

(Continued)

See accompanying notes to financial statements

Alameda Municipal Power
Electric Enterprise Fund
Statements of Net Position
June 30, 2025 and 2024

LIABILITIES	2025	2024
CURRENT LIABILITIES		
Accounts payable and accrued payroll	$1,941,405	$2,998,108
Due to City of Alameda (Note 5)	2,844,553	
Interest payable	361,502	420,644
Refundable deposits	7,826,138	7,443,781
Current portion of long term debt (Note 4)	1,935,000	1,815,000
Current portion of compensated absences (Note 1C)	1,167,587	602,387
Current portion of claims liability (Note 10B)	161,793	207,964
Current portion of lease liability (Note 11B)	307,545	287,969
Total current liabilities	16,545,523	13,775,853
NON-CURRENT LIABILITIES		
Long term debt, net of current portion (Note 4)	11,505,000	13,440,000
Claims liability (Note 10B)	552,767	820,417
Net pension liability (Note 6)	24,993,984	26,538,237
Net OPEB liability (Note 7)	958,114	1,002,488
Lease liability (Note 11B)	1,792,292	2,099,837
Total non-current liabilities	39,802,157	43,900,979
TOTAL LIABILITIES	56,347,680	57,676,832
DEFERRED INFLOWS OF RESOURCES		
Balancing account (Note 1C)	57,926,500	47,888,828
Pension related (Note 6)	672,149	83,491
OPEB related (Note 7)	272,539	347,365
Total deferred inflows of resources	58,871,188	48,319,684
NET POSITION (Note 1E)		
Net investment in capital assets	27,673,212	18,677,596
Restricted for debt service (Note 2I)	5,440,578	5,258,532
Unrestricted	52,643,790	53,554,547
TOTAL NET POSITION	$85,757,580	$77,490,675

See accompanying notes to financial statements

Alameda Municipal Power

Electric Enterprise Fund

Statements of Revenues, Expenses and Changes in Fund Net Position

Years Ended June 30, 2025 and 2024

	2025	2024
OPERATING REVENUES		
Sales	$76,525,668	$72,283,912
Miscellaneous services	593,038	656,643
Plant leased to others	140,912	132,070
Jobbing sales	1,202,689	1,874,528
Cap and trade revenue	2,010,849	3,179,665
Greenhouse gas related sales	452,162	
Low carbon fuel standard credit sales	995,569	
Total operating revenues	81,920,887	78,126,818
OPERATING EXPENSES		
Purchased power	32,416,136	35,696,806
Energy efficiency, solar and other	1,317,000	1,637,182
Operations and maintenance	9,831,397	8,104,162
Customer service, information systems	3,406,570	3,113,980
Administrative and general	10,797,776	11,854,975
Depreciation and amortization (Note 5)	3,631,695	3,335,839
Customer relations	481,324	400,463
Jobbing sales expense	1,202,689	1,874,528
Balancing account adjustment	10,037,672	6,115,571
Total operating expenses	73,122,259	72,133,506
OPERATING INCOME	8,798,628	5,993,312
NONOPERATING REVENUES (EXPENSES)		
Interest income on unrestricted investments	3,866,039	3,482,735
Fair Market Value Adjustment	1,179,689	1,005,056
Interest income on restricted investments	173,848	190,531
Interest expense	(852,375)	(978,991)
Gain from sales of capital assets	71,259	
Other income (expense)	(9,777)	(2,533)
Increase (decrease) in value of certain NCPA projects and reserves	1,146,366	(23,756)
Alameda Point phone maintenance - Net	33,593	34,990
Miscellaneous income (expense)	24,635	20,737
Payment in-lieu of taxes (Note 5)	(1,652,000)	(1,621,000)
Total nonoperating revenue (expense)	3,981,277	2,107,769
INCOME BEFORE TRANSFERS	12,779,905	8,101,081
Transfers to City of Alameda (Note 5)	(4,513,000)	(4,382,000)
CHANGE IN NET POSITION	8,266,905	3,719,081
NET POSITION, BEGINNING OF YEAR	77,490,675	73,771,594
NET POSITION, END OF YEAR	$85,757,580	$77,490,675

See accompanying notes to financial statements

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Alameda Municipal Power
Electric Enterprise Fund
Statements of Cash Flows (Continued)
For the Year Ended June 30, 2025 and 2024

	2025	2024
CASH FLOWS FROM OPERATING ACTIVITIES		
Receipts from customers	$77,105,421	$71,495,653
Receipts from Special Sales (C&T and REC)	5,395,219	5,842,906
Payments to suppliers	(39,058,139)	(40,057,424)
Payments to employees and related benefits	(17,771,400)	(20,602,589)
Net cash provided by operating activities	25,671,101	16,678,546
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Transfers to General Fund of City of Alameda	(4,513,000)	(4,382,000)
Payments in-lieu of taxes	(1,652,000)	(1,621,000)
Net cash (used) for noncapital financing activities	(6,165,000)	(6,003,000)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Purchase of Capital Assets	(10,585,992)	(3,592,932)
Gain from sales of capital assets	71,259	
Long-term debt repayments	(1,815,000)	(1,705,000)
Interest paid on long-term debt	(914,026)	(1,040,641)
Net cash (used) for capital and related financing activities	(13,243,759)	(6,338,573)
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest receipts	173,848	190,531
Proceeds from sale or maturity of unrestricted investments	25,009,658	16,157,994
Proceeds from investments designated for special purposes	3,975,573	143,518
Proceeds (purchases) from investments in certain NCPA projects and reserves	(409,776)	(983,269)
Purchases of investments in restricted assets	(182,046)	(212,225)
Purchases of unrestricted investments	(23,044,788)	(14,895,240)
Net cash (used) for investing activities	5,522,469	401,309
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	11,784,811	4,738,282
Cash, beginning of year	40,161,267	35,422,985
Cash, end of year	$51,946,078	$40,161,267

(Continued)

See accompanying notes to financial statements

Alameda Municipal Power
Electric Enterprise Fund
Statements of Cash Flows
For the Year Ended June 30, 2025 and 2024

	2025	2024
Reconciliation of operating (loss) to net cash provided by operating activities:		
Operating income	8,798,628	5,993,312
Adjustments to reconcile operating losses to cash flows from operating activities:		
Depreciation and amortization	3,631,695	3,335,839
Changes in assets and liabilities:		
Pension expense	1,290,443	2,149,457
OPEB expense	(158,410)	(142,623)
Decrease (increase) in accounts receivable	579,753	(788,259)
Decrease (increase) in materials and supplies	(919,579)	(1,611,458)
Decrease (increase) in prepaids	(10,687)	
Increase (decrease) in accounts payable and accrued payroll	(1,056,703)	1,439,353
Increase (decrease) in due to the City of Alameda	2,844,553	(365,218)
Increase (decrease) in balancing account	10,037,672	6,115,571
Increase (decrease) in refundable deposits	382,357	372,628
Increase (decrease) in compensated absences	565,200	(10,077)
Increase (decrease) in claims liability	(313,821)	190,021
Increase (decrease) in deferred amount on refunding		
Net cash provided (used) by operating activities	$25,671,101	$16,678,546
SCHEDULE OF NON CASH ACTIVITY		
Change in fair value of investments	$3,975,573	$3,482,735

See accompanying notes to financial statements

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NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. General

Alameda Municipal Power (AMP) is a department of the City of Alameda (City) that operates the electric system. AMP provides this service to the businesses and residents of the City, Alameda Point (former Alameda Naval Air Station) and Coast Guard Island. AMP is under the policy control of the Public Utilities Board (Board), as set forth in the City Charter. The Board consists of five members appointed by the City Council, one of whom is the City Manager. The accompanying financial statements only reflect the activity of AMP, an enterprise fund of the City. These financial statements present only AMP and do not purport to, and do not, present fairly the financial position of the City and the changes in its financial position and cash flows, where applicable, in conformity with accounting principles generally accepted in the United States of America.

B. Basis of Presentation

AMP's basic financial statements are prepared in conformity with accounting principles generally accepted in the United States of America. The Governmental Accounting Standards Board is the acknowledged standard setting body for establishing accounting and financial reporting standards followed by governmental entities in the United States of America.

C. Basis of Accounting

AMP is accounted for as an enterprise fund (proprietary fund type). A fund is an accounting entity with a self-balancing set of accounts established to record the financial position and results of operations of a specific activity. The activities of an enterprise fund closely resemble those of the private sector in which the purpose is to conserve and add to economic resources. Enterprise funds account for operations that provide services on a continuous basis and are substantially financed by revenues derived from user charges.

The financial statements are reported using the economic resources measurement focus and the accrual basis of accounting. Revenues are recorded when earned and expenses are recorded at the time liabilities are incurred, regardless of when the related cash flows take place.

Investments in Joint Ventures – AMP records its equity in the general operating reserve of the Northern California Power Agency (NCPA), and its net equity in those projects in which it participates, as discussed in Note 8. AMP's share of individual project obligations has been netted against its share of the related project assets, as reported by NCPA, because AMP does not actively manage these projects and does not expect to become directly liable for any of the obligations of these projects. Amounts paid to the Transmission Agency of Northern California (TANC) are expensed currently because AMP's estimated equity, if any, in TANC is not material, as discussed in Note 9. Amounts paid to the Local Agency Workers Compensation Excess Joint Powers Authority are charged currently to insurance expense, as discussed in Note 10.

Cash and Cash Equivalents – For purposes of the statements of cash flows, AMP defines cash and cash equivalents to include all cash and temporary investments with original maturities of three months or less from the date of acquisition.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Investments – are carried at fair value, as required by generally accepted accounting principles in the United States of America. AMP adjusts the carrying value of its investments to reflect their fair value at each fiscal year end, and it includes the effects of these adjustments in income for that fiscal year.

Materials and Supplies – are valued at average cost and are used primarily for internal purposes.

Maintenance and Repairs – are charged to maintenance expense as incurred.

Capital Assets – are valued at historical cost or estimated historical cost if actual historical cost is not available, except for intangible right-to-use lease assets, the measurement of which is discussed in Note 1J below. AMP capitalizes all assets with a historical cost of at least $10,000 and a useful life of at least three years.

All capital assets with limited useful lives are depreciated over their estimated useful lives. The purpose of depreciation is to spread the cost of capital assets equitably among all users over the life of these assets. The amount charged to depreciation expense each year represents that year's pro rata share of the cost of capital assets.

Depreciation is provided using the straight-line method which means the cost of the asset is divided by its expected useful life in years and the result is charged to expense each year until the asset is fully depreciated. AMP has assigned the useful lives listed below to capital assets:

Utility Plant and Buildings	30-50 years
Machinery and Equipment	10-40 years
Transportation Equipment	5-10 years
Computer Equipment	5 years
Furniture and Fixtures	25 years
Right-to-use Leased Building	10 years

Major outlays for capital assets and improvements are capitalized as projects are constructed.

Some capital assets may be acquired using federal and state grant funds, or they may be contributed by developers or other governments. Contributions are accounted for at their acquisition cost at the time the capital assets are contributed.

Deferred Outflows and Inflows of Resources – Deferred outflows of resources represent a consumption of net assets that applies to future periods and deferred inflows of resources represent an acquisition of net assets that applies to future periods. A deferred outflow of resources has a positive effect on net position, similar to assets, and a deferred inflow of resources has a negative effect on net position, similar to liabilities. AMP has certain items, which qualify for reporting as deferred outflows of resources and deferred inflows of resources.

Deferred Outflows of Resources – ***Deferred Loss on Refunding*** – is used by AMP to report the difference in the carrying value of the refunded debt and its reacquisition price for the 2010A/B Refunding Bonds. This amount is deferred and amortized over the shorter of the life of the refunded or refunding debt.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Deferred Inflows of Resources – ***Balancing Account*** – is used by AMP to help stabilize rates. Specifically, the balancing account accumulates differences between the actual costs of providing a utility service with the related revenues designated for recovery of such costs. Deferred amounts are refunded to or recovered from customers through authorized rate adjustments, but can be reciprocally the beneficiaries of any temporary over-collection. The effect of using the balancing account is that unanticipated changes in sales levels and purchased power costs do not immediately affect AMP's rates because they are included in operating expenses as they are matched by revenues.

Deferred Inflows and Outflows Related to Pensions – Deferred outflows related to pensions relates to the payment of pension contributions after the measurement date and differences between expected and actual experience. Deferred inflows related to pensions relates to the net differences between projected and actual earnings on pension plan investments, changes of assumptions, and differences between actual and expected experience. See Note 6 for further discussion.

Deferred Inflows and Outflows Related to Other Postemployment Benefits (OPEB) – Deferred outflows related to OPEB relates to the payment of OPEB contributions after the measurement date, the net differences between projected and actual earnings on plan investments and changes of assumptions. Deferred inflows related to OPEB relates to changes of assumptions and differences between actual and expected experience. See Note 7 for further discussion.

Refundable Deposits – Customer deposits are required by AMP from commercial customers when they establish their account. Deposits from residential customers are not required unless they abuse their credit privileges. Developers requesting higher rated transformers are required to provide deposits that are retained by AMP for approximately three years. At the end of the three-year period, AMP will evaluate the usage and determine if the transformer requirements are met. Developers also prepay for the distribution system substructure and part of the trunk costs for new developments within Alameda.

Unearned Revenue – AMP reports unearned revenue in connection with resources that have been received, but not yet earned.

Compensated Absences – Including accumulated unpaid vacation, sick pay and other employee benefits are accounted for as expenses in the year earned. The liability for compensated absences includes the vested portions of vacation and compensated time off. The liability is calculated in accordance with generally accepted accounting principles and based on whether or not is it more likely than not that leave will be used before the employee leaves the District.

Changes in compensated absences payable consist of the following as of June 30:

	2025	2024
Beginning Balance	$602,387	$612,464
Net Change	565,200	(10,077)
Ending Balance	$1,167,587	$602,387
Current Portion	$1,167,587	$602,387

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Sales Revenues – Sales of electricity are recognized based on cycle billings periodically rendered to customers. Revenues for services provided but not billed at the end of a fiscal year are recognized and accrued based on the estimated consumption.

D. Budgets and Budgetary Accounting

Although not required by California Government Code, AMP adopts an annual budget to serve as its approved financial plan. AMP follows these procedures in establishing the budget:

1. The General Manager submits to the Board a proposed operating budget for the fiscal year commencing the following July 1. The operating budget includes proposed expenditures and the means of financing them.

2. Ratepayer comments are solicited during regular Public Utilities Board meetings.

3. The budget is legally enacted through passage of a resolution.

4. The General Manager is authorized to transfer budgeted amounts between divisions; however, any revisions that increase the total expenditures must be approved by the Board. Expenditures may not legally exceed budgeted appropriations at the fund level without Board approval.

5. Unexpended appropriations lapse at year-end and must be re-appropriated in the following year.

6. Formal budgetary integration is employed as a management control device during the year.

7. Budgets are adopted on a basis consistent with generally accepted accounting principles, except that AMP budgets capital asset outlays as current year expenditures.

E. Net Position

It is AMP’s policy to apply restricted resources first when an expense is incurred for purposes for which both restricted and unrestricted net position is available.

Net Position is the excess of all AMP's assets and deferred outflows over all its liabilities and deferred inflows, regardless of fund. Net Position is divided into the captions below:

Net Investment in Capital Assets describes the portion of net position which is represented by the current net book value of AMP's capital assets, less the outstanding balance of any debt issued to finance these assets.

Restricted describes the portion of net position which is restricted as to use by the terms and conditions of agreements with outside parties, governmental regulations, laws, enabling legislation, or other restrictions which AMP cannot unilaterally alter.

Unrestricted describes the portion of net position which is not restricted to use.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Designations are imposed by the Board to reflect future spending plans or concerns about the availability of future resources. Designations may be modified, amended or removed by Board action and are classified under unrestricted net position.

F. Classification of Revenues

Operating revenues consist mainly of electric services sales. Operating revenues are used to finance the cost of operations, including the cost of delivering and providing services, maintenance and recurring capital replacement and paying debt service. All other revenues and expenses not meeting this definition are reported as nonoperating revenues and expenses.

AMP distinguishes operating revenues and expenses from nonoperating items. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with AMP’s principal ongoing operations. The principal operating revenues are charges to customers for sales and services. Operating expenses include the cost of sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as nonoperating revenues and expenses.

G. Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, deferred outflows of resources, deferred inflows of resources and disclosures at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

H. Pension

For purposes of measuring the net pension liability, deferred outflows of resources and deferred inflows of resources related to pensions, and pension expense, information about the fiduciary net position of AMP’s proportionate share of the City of Alameda’s agent multiple-employer defined benefit miscellaneous retirement plan (the Plan) administered by California Public Employees’ Retirement System (CalPERS) and additions to deductions from the Plan’s net position have been determined on the same basis as they are reported by the Plan. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value.

I. OPEB

For purposes of measuring the net other post-employment benefits (OPEB) liability, deferred outflows of resources and deferred inflows of resources related to OPEB, and OPEB expense, information about the fiduciary net position of AMP's proportionate share of the City's Single-Employer OPEB Plan, as administered by the City, and additions to/deductions from the Plan's fiduciary net position have been determined on the same basis as they are reported by the Plan. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

J. Leases

A lease is defined as a contract that conveys control of the right to use another entity's nonfinancial asset (the underlying asset) as specified in the contract for a period of time in an exchange or exchange-like transaction. Examples of nonfinancial assets include buildings, land, vehicles, and equipment.

Lessee – AMP is a lessee for noncancellable leases of a building. AMP recognizes a lease liability and an intangible right-to-use lease asset (lease asset) in the financial statements. AMP recognizes lease liabilities with an initial individual value of $10,000 or more.

At the commencement of a lease, AMP initially measures the lease liability at the present value of payments expected to be made during the lease term. Subsequently, the lease liability is reduced by the principal portion of lease payments made. The lease asset is initially measured as the initial amount of the lease liability, adjusted for lease payments made at or before the lease commencement date, plus certain initial direct costs. Subsequently, the lease asset is amortized on a straight-line basis over the lesser of its useful life or the life of the lease agreement.

Key estimates and judgments related to leases include how AMP determines (1) the discount rate it uses to discount the expected lease payments to present value, (2) lease term, and (3) lease payments as follows:

- AMP uses the interest rate charged by the lessor as the discount rate. When the interest rate charged by the lessor is not provided, AMP generally uses its estimated incremental borrowing rate as the discount rate for leases.

- The lease term includes the noncancellable period of the lease.

- Lease payments included in the measurement of the lease liability are composed of fixed payments and purchase option price that AMP is reasonably certain to exercise, if applicable.

AMP monitors changes in circumstances that would require a remeasurement of its lease and will remeasure the lease asset and liability if certain changes occur that are expected to significantly affect the amount of the lease liability.

Lease assets are reported with other capital assets and lease liabilities are reported with long-term lease liabilities on the statement of net position.

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

K. New and Upcoming Governmental Accounting Standards Board Statement Pronouncements

GASB Statement No. 103 – In April 2024, GASB issued Statement No. 103, Financial Reporting Model Improvements. The objective of this Statement is to improve key components of the financial reporting model to enhance its effectiveness in providing information that is essential for decision making and assessing a government's accountability. This Statement also addresses certain application issues. The requirements of this statement are effective for the District's fiscal year ending June 30, 2026.

GASB Statement No. 104 – In September 2024, GASB issued Statement No. 104, Disclosure of Certain Capital Assets. The objective of this Statement is to provide users of government financial statements with essential information about certain types of capital assets. This Statement requires certain types of capital assets to be disclosed separately in the capital assets note disclosures required by Statement 34 and also requires additional disclosures for capital assets held for sale. The requirements of this statement are effective for the District's fiscal year ending June 30, 2026.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS

A. Classification

Cash and investments are classified in the financial statements as shown below, based on whether or not their use is restricted under the terms of AMP debt instruments.

Cash and investments as of June 30 are as follows:

	2025	2024
Cash and cash equivalents	$51,946,078	$40,161,267
Investments	37,477,312	34,598,854
Restricted Investments	5,440,578	5,258,532
Investments designated for special purposes	31,386,625	35,362,198
Total Cash and Investments	$126,250,593	$115,380,851

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

B. Policies

California law requires banks and savings and loan institutions to pledge government securities with a market value of 110 percent of AMP's cash on deposit, or first trust deed mortgage notes with a market value of 150 percent of the deposit, as collateral for these deposits. Under California law this collateral is held in a separate investment pool by another institution in AMP's name and places AMP ahead of general creditors of the institution.

AMP and its fiscal agents invest in individual investments and in investment pools. Individual investments are evidenced by specific identifiable securities instruments, or by an electronic entry registering the owner in the records of the institution issuing the security, called the book entry system. Individual investments are generally made by AMP's fiscal agents as required under its debt issues.

C. Investments Authorized by the California Government Code and AMP's Investment Policy

AMP's investment policy and the California Government Code allow AMP to invest in the following, provided the credit ratings of the issuers are acceptable to AMP, and approved percentages and maturities are not exceeded. The table below also identifies certain provisions of the California Government Code, or AMP's Investment Policy where AMP's Investment Policy is more restrictive, that addresses interest rate risk, credit risk and concentration of credit risk.

This table does not address investments of debt proceeds held by bond trustees that are governed by the provisions of debt agreements of AMP, rather than the general provisions of the California Government Code or AMP's investment policy. AMP's investment policy and the California Government Code allow AMP to invest in the investments in the table below:

Authorized Investment Type	Maximum Remaining Maturity	Maximum Investment in One Issuer	Maximum Percentage Percentage of Portfolio	Minimum required rating
Bank/Time Deposits	5 years	No limit	No limit	N/A
U.S. Treasury Obligations	5 years	No limit	No limit	N/A
U.S. Agency Securities	5 years	25%	75%	N/A
Mutual Funds and Money Market Funds	5 years	10%	20%	Highest rating by 2 NRSROs
Bankers Acceptances	180 days	5%	30%	A1/P1 or its equivalent
Commercial Paper	270 days	5%	40% (under the provision Sunsetting on 1/1/26)	A1/P1 or its equivalent (with issuer rated A or its equivalent)
Non-Negotiable Certificates of Deposit/CDARS	3 years	5%	30% (combined with NCDs)	N/A
Negotiable Certificates of Deposit	5 years	5%	30% (combined with CDARS)	No Rating for amount under FDIC Insurance; A-1/A for amounts greater than FDIC Insurance
Local Agency Investment Fund (LAIF)	N/A	No limit	LAIF Limit	N/A
CAMP/Caltrust	N/A	No limit	No limit	N/A
Municipal Obligations	5 years	5%	30%	A (except City's own bonds)
Medium Term Notes	5 years	5%	30%	A or equivalent
Supranationals	5 years	10%	15%	AA or equivalent
Asset-Backed Securities	5 years	5%	20%	AA or equivalent (with issuer rated A or equivalent)

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

D. Investments Authorized by Debt Agreements

AMP must maintain required amounts of cash and investments with trustees or fiscal agents under the terms of certain debt issues. These funds are unexpended bond proceeds or are pledged as reserves to be used if AMP fails to meet its obligations under these debt issues. The California Government Code requires these funds to be invested in accordance with AMP's ordinance, bond indentures or State Statute. The table on the next page identifies the investment types that are authorized for investments held by fiscal agents.

The table also identifies certain provisions of these debt agreements:

Authorized Investment Type	Maximum Remaining Maturity	Maximum Investment in One Issuer	Maximum Percentage Allowed Percentage of Portfolio	Minimum required rating
U.S Treasury Obligations	N/A	No limit	No limit	N/A
State Obligations	N/A	No limit	No limit	N/A
U.S. Agency Securities (a)	N/A	No limit	No limit	N/A
Commercial Paper	N/A	5%	25%	A1/P1/A
Certificates of Deposit	5 years	5%	30%	A1/A
Bankers Acceptances	180 days	5%	30%	A1/P1
Money Market Mutual Funds	N/A	No limit	20%	A
Local Agency Investment Fund	N/A	LAIF limit	No limit	N/A
Investment Agreements (b)	N/A	No limit	No limit	AA

(a) Securities issued by agencies of the Federal government such as the Federal Farm Credit Bank (FFCB), the Federal Home Loan Bank (FHLB), the Federal National Mortgage Association (FNMA), and the Federal Home Loan Mortgage Corporation (FHLMC).
(b) Investment agreements, including guaranteed investment contracts, repurchase agreements, forward purchase agreements and reserve fund put agreements.

E. Interest Rate Risk

Interest rate risk is the risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates. One of the ways that AMP manages its exposure to interest rate risk is by purchasing a combination of shorter term and longer-term investments and by timing cash flows from maturities so that a portion of the portfolio is maturing or coming close to maturity evenly over time as necessary to provide the cash flow and liquidity needed for operations.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

Information about the sensitivity of the fair values of AMP's investments (including investments held by bond trustees) to market interest rate fluctuations is provided by the following table that shows the distribution of AMP's investments by maturity, as of June 30:

	2025			
Investment Type	12 Months or less	13 to 24 Months	25 to 60 Months	Total
U.S. Agency Securities				
Non-callable	$2,376,641		$999,505	$3,376,146
Callable	489,235	$886,276	748,745	2,124,256
U.S. Treasury Notes	2,948,610			2,948,610
U.S. Treasury Bonds	9,021,412			9,021,412
Local Agency Investment Fund	71,318,035			71,318,035
Corporate Bonds				
Non-callable	2,729,224	967,490		3,696,714
Callable	1,662,522	485,798	1,041,115	3,189,435
Non-Negotiable Certificates of Deposit	3,405,674			3,405,674
Negotiable Certificates of Deposit	1,288,832	150,242	245,575	1,684,649
Municipal Obligations	5,155,200	1,453,361	945,879	7,554,440
Money Market Mutual Funds	475,976			475,976
Held by fiscal agent:				
Money Market Mutual Funds	5,440,578			5,440,578
Total Investments	106,311,939	3,943,167	3,980,819	114,235,925
Total Cash in bank and petty cash				12,014,668
Total Cash and Investments	$106,311,939	$3,943,167	$3,980,819	$126,250,593

	2024			
Investment Type	12 Months or less	13 to 24 Months	25 to 60 Months	Total
U.S. Agency Securities				
Non-callable	$247,030	$1,689,248	$438,649	$2,374,927
Calllable	739,761	399,381	299,715	1,438,857
U.S. Treasury Notes	9,314,395			9,314,395
U.S. Treasury Bonds		570,006		570,006
Local Agency Investment Fund	67,177,805			67,177,805
Corporate Bonds				
Non-callable		1,498,707	928,255	2,426,962
Calllable	541,208	2,232,254	2,782,873	5,556,335
Non-Negotiable Certificates of Deposit	2,300,625	632,062		2,932,687
Negotiable Certificates of Deposit	998,128	1,002,841	890,232	2,891,201
Municipal Obligations	2,693,512	2,954,175	1,253,969	6,901,656
Money Market Mutual Funds	191,829			191,829
Held by fiscal agent:				
Money Market Mutual Funds	5,258,532			5,258,532
Total Investments	89,462,825	10,978,674	6,593,693	107,035,192
Total Cash in bank and petty cash				8,345,659
Total Cash and Investments	$89,462,825	$10,978,674	$6,593,693	$115,380,851

AMP is a participant in the Local Agency Investment Fund (LAIF) that is regulated by California Government Code Section 16429 under the oversight of the Treasurer of the State of California. AMP reports its investment in LAIF at the fair value amount provided by LAIF, which is the same as the value of the pool share. The balance is available for withdrawal on demand and is based on the accounting records maintained by LAIF, which are recorded on an amortized cost basis. LAIF is not registered with the Securities and Exchange Commission and is not rated.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

F. Fair Value Measurement

AMP categorizes the fair value measurements of its investments based on the hierarchy established by generally accepted accounting principles. The fair value hierarchy, which has three levels, is based on the valuation inputs used to measure an assets' fair value: Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs such as quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in inactive markets; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means; Level 3 inputs are significant unobservable inputs.

Deposits and withdrawals in Local Agency Investment Fund (LAIF) are made on the basis of $1 and amounts are reported on an amortized basis which approximates fair value. Accordingly, AMP's proportionate share in LAIF is an uncategorized input not defined as Level 1, Level 2, or Level 3 input.

The following is a summary of the fair value hierarchy of the fair value of investments as of June 30, 2025:

	2025	
Investment Type	Level 2	Total
Investments by Fair Value:		
U.S. Agency Securities	$5,500,402	$5,500,402
U.S. Treasury Notes	2,948,610	2,948,610
U.S. Treasury Bonds	9,021,412	9,021,412
Corporate Bonds	6,886,149	6,886,149
Negotiable Certificates of Deposit	1,684,649	1,684,649
Non-Negotiable Certificates of Deposit	3,405,674	3,405,674
Municipal Obligations	7,554,440	7,554,440
Total	$37,001,336	37,001,336
Investments Exempt from Fair Value Hierarchy:		
California Local Agency Investment Fund		71,318,035
Investments Measured at Amortized Cost:		
Money Market Mutual Funds		475,976
Money Market Funds Held with Fiscal Agents		5,440,578
Total Investments		$114,235,925

U.S. Agency Securities, U.S. Treasury Notes, U.S. Treasury Bonds, Corporate Bonds, Certificates of Deposit and Municipal Obligations totaling $37,001,336 classified in Level 2 of the fair value Hierarchy, are valued using matrix pricing techniques-maintained by various pricing vendors. Matrix pricing is used to value securities based on the securities' relationship to benchmark quoted prices.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

The following is a summary of the fair value hierarchy of the fair value of investments as of June 30, 2024:

	2024	
Investment Type	Level 2	Total
Investments by Fair Value Level:		
U.S. Agency Securities	$3,813,784	$3,813,784
U.S. Treasury Notes	9,314,395	9,314,395
U.S. Treasury Bonds	570,006	570,006
Corporate Bonds	7,983,297	7,983,297
Non-Negotiable Certifcates of Deposit	2,891,201	2,891,201
Negotiable Certificates of Deposit	2,932,687	2,932,687
Municipal Obligations	6,901,656	6,901,656
Total	$34,407,026	34,407,026
Investments Exempt from Fair Value Hierarchy:		
California Local Agency Investment Fund		67,177,805
Investments Measured at Amortized Cost:		
Money Market Mutual Funds		191,829
Money Market Funds Held with Fiscal Agents		5,258,532
Total Investments		$107,035,192

U.S. Agency Securities, Corporate Bonds, Certificates of Deposit and Municipal Obligations totaling $34,407,026 classified in Level 2 of the fair value Hierarchy, are valued using matrix pricing techniques-maintained by various pricing vendors. Matrix pricing is used to value securities based on the securities' relationship to benchmark quoted prices.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

G. Credit Risk

Generally, credit risk is the risk that an issuer of an investment will not fulfill its obligation to the holder of the investment. This is measured by the assignment of a rating by a nationally recognized statistical rating organization. Presented below is the actual rating of each investment type as provided by Moody's investment rating system as of June 30:

	2025			
Investment Type	AAA/Aaa	AA+/AA/AA-	A+/A/A-	Total
Money Market Mutual Funds	$5,916,554			$5,916,554
U.S. Agency Securities				
Non-callable		$2,825,849		2,825,849
Callable		1,737,440		1,737,440
Corporate Bonds				
Non-callable		1,711,387	$1,625,686	3,337,073
Callable		150,200	2,849,915	3,000,115
Municipal Obligations		5,626,442	894,241	6,520,683
Total	$5,916,554	$12,051,318	$5,369,842	23,337,714
Not Rated:				
U.S. Agency Securities:				
Non-callable				550,297
Callable				386,816
Corporate Bonds:				
Non-callable				359,641
Callable				189,320
Municipal Obligations				1,033,757
Non-Negotiable Certificates of Deposit				3,405,674
Negotiable Certificates of Deposit				1,684,649
Local Agency Investment Fund				71,318,035
Exempt:				
US Treasury Notes				2,948,610
US Treasury Bonds				9,021,412
Cash in bank and petty cash				12,014,668
Total Cash and Investments				$126,250,593

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

	2024			
Investment Type	AAA/Aaa	AA+/AA/AA-	A+/A/A-	Total
Money Market Mutual Funds (Bond)	$5,450,361			$5,450,361
US Agency Securities				
Non-callable		$1,853,131		1,853,131
Callable		1,438,857		1,438,857
Corporate Bonds				
Non-callable		1,369,355	$245,610	1,614,965
Callable		595,176	5,252,279	5,847,455
Municipal Obligations	224,829	5,037,586	756,049	6,018,464
Total	$5,675,190	$10,294,105	$6,253,938	22,223,233
Not Rated:				
U.S. Agency Securities				
Non-callable				521,796
Callable				
Corporate Bonds:				
Non-callable				342,257
Callable				178,620
Municipal Obligations				883,192
Non-Negotiable Certificates of Deposit				2,932,687
Negotiable Certificates of Deposit				2,891,201
Local Agency Investment Fund				67,177,805
Exempt:				
US Treasury Notes				9,314,395
US Treasury Bonds				570,006
Cash in bank and petty cash				8,345,659
Total Cash and Investments				$115,380,851

Custodial Credit Risk

Custodial credit risk for deposits is the risk that, in the event of the failure of a depository financial institution, AMP will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party. The custodial credit risk for investments is the risk that, in the event of the failure of the counterparty (e.g., broker-dealer) to a transaction, a government will not be able to recover the value of its investment or collateral securities that are in the possession of another party. The California Government Code has provisions for financial institutions that limit custodial credit risk for deposits. Financial institutions are required to secure deposits made by State or local government units by pledging securities in an undivided collateral pool held by a depository regulated under State law. The market value of the pledged securities in the collateral pool must equal at least 110 percent of the total amount deposited by public agencies. California law also allows financial institutions to secure AMP deposits by pledging first trust deed mortgage notes having a value of 150 percent of the secured public deposits. AMP's financial institutions also have insurance through the Federal Depository Insurance Corporation (FDIC). AMP's investment policy has no additional provisions for limiting custodial credit risk for deposits.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

As of June 30, 2025, AMP's bank balance of $12,227,118 was either collateralized or insured by the Federal Deposit Insurance Corporation (FDIC). AMP's deposits with Hilltop Securities were insured up to $250,000 by FDIC. Hilltop Securities also had Securities Investor Protection Corporation (SIPC) coverage which provided an additional $500,000 coverage. Furthermore, Hilltop Securities had private insurance in excess of SIPC coverage with a $1.9M per-client limit. As of June 30, 2025, AMP's investments balance with Hilltop Securities was $37,477,312.

Investments

As of June 30, 2025, none of AMP's investments were held with counterparty. All of AMP's investments were held with an independent third-party custodian bank. All of AMP investments held in custody and safekeeping are held in the name of AMP and segregated from securities owned by the bank. This is the lowest level of custodial credit risk exposure.

H. Concentration of Credit Risk

Concentration of credit risk is the loss risk attributed to the magnitude of investment in a single issuer. AMP's investment policy places certain maximum percentage limitations of investments by investment type and AMP have adhered to this policy with no exception.

I. Restricted Assets

Restricted assets as of June 30 are as follows:

	2025	2024
Restricted by Revenue Bond 2010 A&B		
Indenture-Reserve Fund-Bond Mutual Funds	$2,342,960	$2,288,305
Restricted by Revenue Bond Series 2010 A&B		
Indenture-Reserve Fund-Bond Mutual Funds	3,097,618	2,970,227
Total Restricted Assets	$5,440,578	$5,258,532

Restricted by Revenue Bond Series 2010A&B Indenture - Bond Fund represents investments held with fiscal agent as required by the Revenue Bond indenture. The funds held by the trustee are to be used for the defeasance of certain obligations with respect to the Series 2010 A/B Revenue Bonds.

Restricted by Revenue Bond Series 2010A&B Indenture - Reserve Fund represents investments held with fiscal agent as required by the Revenue Bond indenture. The funds held by the trustee are to meet the "Common Reserve Fund Requirement" of the indenture.

NOTE 2 – CASH AND INVESTMENTS AND RESTRICTED ASSETS (Continued)

J. Designated Investments

Investments designated by the Board for special purposes comprise of the following as of June 30:

	2025	2024
Insurance Reserve	$1,200,000	$1,200,000
Underground Special Fund	11,269,174	15,664,793
Renewable Energy Credits Energy Reserve	16,095,944	16,109,599
Cap and Trade Net Revenue Reserve	1,805,357	1,794,512
Low Carbon Fuel Standard Revenue Reserve	1,016,150	593,294
Total	$31,386,625	$35,362,198

Insurance Reserve – This reserve represents a portion of the retained risk, or deductible amount under AMP's liability insurance policy, which is purchased independent of the City's overall insurance program.

Underground Special Fund – This reserve represents the amount set aside for the funding of the conversion of overhead facilities to underground facilities.

Renewable Energy Credits (REC) Energy Reserve – This reserve represents the set aside of the resources generated from the sale of renewable energy credits through the REC trading markets regulated by the California Energy Commission.

Cap and Trade Net Revenue Reserve – This reserve represents the set aside of resources generated by the Cap and Trade program which took effect in early 2012 to reduce greenhouse gas (GHG) emissions and is regulated by the California Air Resources Board.

Low Carbon Fuel Standard Revenue Reserve – This reserve represents the set aside of resources generated from the sale of the banked credits to reduce the carbon intensity of transportation fuels in California by 10 percent by 2020. The program is administered by the California Air Resources Board (CARB).

NOTE 3 – CAPITAL ASSETS

Capital asset activity for the years ended June 30, 2025 and 2024 is as follows:

	Balance at June 30, 2024	Additions	Retirements	Transfers & Adjustments	Balance at June 30, 2025
Capital assets not being depreciated:					
Land and Rights	$220,143				$220,143
Construction Work in Progress	7,699,684	$10,336,564		($4,123,036)	13,913,212
Total capital assets not being depreciated	7,919,827	10,336,564		(4,123,036)	14,133,355
Capital assets being depreciated and amortized:					
Utility Plant	92,066,257			2,797,513	94,863,770
Service Center Building	8,168,069				8,168,069
Machinery and Equipment	10,118,053			(23,408)	10,094,645
Transportation Equipment	4,536,409	249,429	($2,056,177)	1,490,730	4,220,391
Computer Equipment	5,252,015			(139,216)	5,112,799
Furniture and Fixtures	980,488			(2,583)	977,905
Intangible right-to-use building	3,142,914				3,142,914
Total capital assets being depreciated	124,264,205	249,429	(2,056,177)	4,123,036	126,580,493
Less accumulated depreciation and amortization:					
Utility Plant	71,375,810	2,511,954		419,699	74,307,463
Service Center Building	5,323,548	158,903			5,482,451
Machinery and Equipment	9,734,673	114,431		(17,792)	9,831,312
Transportation Equipment	3,452,143	354,574	(2,056,177)	(8,889)	1,741,651
Computer Equipment	4,478,002	154,896		(392,381)	4,240,517
Furniture and Fixtures	794,141	17,319		(637)	810,823
Intangible right-to-use building	958,855	319,618			1,278,473
Total accumulated depreciation	96,117,172	3,631,695	(2,056,177)		97,692,690
Total capital assets being depreciated, net	28,147,033	(3,382,266)		4,123,036	28,887,803
Capital assets, net	$36,066,860	$6,954,298			$43,021,158

NOTE 3 – CAPITAL ASSETS (Continued)

	Balance at June 30, 2023	Additions	Transfers & Adjustments	Balance at June 30, 2024
Capital assets not being depreciated:				
Land and Rights	$220,143			$220,143
Construction Work in Progress	6,315,866	$3,355,590	($1,971,772)	7,699,684
Total capital assets not being depreciated	6,536,009	3,355,590	(1,971,772)	7,919,827
Capital assets being depreciated and amortized:				
Utility Plant	90,817,974		1,248,283	92,066,257
Service Center Building	8,168,069			8,168,069
Machinery and Equipment	9,951,651		166,402	10,118,053
Transportation Equipment	4,299,067	237,342		4,536,409
Computer Equipment	4,694,928		557,087	5,252,015
Furniture and Fixtures	980,488			980,488
Intangible right-to-use building	3,142,914			3,142,914
Total capital assets being depreciated	122,055,091	237,342	1,971,772	124,264,205
Less accumulated depreciation and amortization:				
Utility Plant	69,015,886	2,359,924		71,375,810
Service Center Building	5,142,589	180,959		5,323,548
Machinery and Equipment	9,635,021	99,652		9,734,673
Transportation Equipment	3,224,109	228,034		3,452,143
Computer Equipment	4,357,186	120,816		4,478,002
Furniture and Fixtures	767,306	26,835		794,141
Intangible right-to-use building	639,236	319,619		958,855
Total accumulated depreciation	92,781,333	3,335,839		96,117,172
Total capital assets being depreciated, net	29,273,758	(3,098,497)	1,971,772	28,147,033
Capital assets, net	$35,809,767	$257,093		$36,066,860

Depreciation and amortization on capital assets and intangibles included in the statement of revenues, expenses and changes in net position for the years ended June 30, 2025 and 2024 was $3,631,696 and $3,335,839 respectively.

4 – LONG-TERM DEBT

A. Composition and Changes

AMP generally incurs long-term debt to finance projects or purchase assets which will have useful lives equal to or greater than the related debt. AMP's debt issues and transactions are summarized below and discussed in detail thereafter.

NOTE 4 – LONG-TERM DEBT (Continued)

AMP does not have any debt that are direct borrowings or direct placements for the year ended June 30, 2025.

Long-term debt activity for the years ended June 30, 2025 and 2024 is as follows:

	Original Issue Amount	Balance June 30, 2024	Retirements	Balance June 30, 2025	Current Portion
Revenue Bonds, Series 2010A	$8,700,000	$8,700,000		$8,700,000	
Taxable Revenue Bonds, Series 2010B	22,985,000	6,555,000	($1,815,000)	4,740,000	$1,935,000
Total Long-Term Debt		$15,255,000	($1,815,000)	$13,440,000	$1,935,000

	Original Issue Amount	Balance June 30, 2023	Retirements	Balance June 30, 2024	Current Portion
Revenue Bonds, Series 2010A	$8,700,000	$8,700,000		$8,700,000	
Taxable Revenue Bonds, Series 2010B	22,985,000	8,260,000	($1,705,000)	6,555,000	$1,815,000
Total Long-Term Debt		$16,960,000	($1,705,000)	$15,255,000	$1,815,000

B. Description of Long-Term Debt Issues

Revenue Bonds, Series 2010A/B (AMP Refinancing) – As described in an indenture agreement dated August 1, 2010, Revenue Bonds, Series 2010A/B were issued through Alameda Public Financing Authority on behalf of AMP to provide funds, together with certain other available monies, to 1) prepay the obligations of AMP for the Electric System Revenue Certificates of Participation Series 2000A, 2) prepay the obligations of AMP for the Taxable Electric System Revenue Certificates of Participation, Series 2000AT, 3) fund a deposit to the Common Reserve Account, and 4) prepay the costs of issuance of the 2010 Bonds. Revenue Bonds, Series 2010A bear interest at 4.375 percent to 5.25 percent, payable January 1 and July 1 of each year. The Revenue Bonds, Series 2010B bear interest at 1.829 percent to 6.517 percent, payable January 1, and July 1 of each year.

Principal on the Series 2010B Bonds will be payable beginning July 1, 2011, and each succeeding July 1 until final maturity in 2027. Principal on the Series 2010A Bonds will be payable beginning July 1, 2027, and each succeeding July 1 until final maturity in 2030. The 2010 Bonds are subject to optional and mandatory sinking fund redemption prior to maturity. The 2010 Bonds are special obligations payable solely from electric revenues, other amounts held in the bond funds and accounts established pursuant to the indenture and amounts on deposit in the Common Reserve Account. The initial book-entry principal obligation for the Series 2010A and Series 2010B bonds was $8,700,000 and $22,985,000, respectively.

AMP does not have unused line of credits for the year ended June 30, 2025.

NOTE 4 – LONG-TERM DEBT (Continued)

AMP's outstanding revenue bonds (Series 2010A) and Taxable Revenue Bonds (Series 2010B) are secured solely by a pledge of net revenues of AMP. Both revenue bonds contain a rate covenant that AMP will at all times fix, prescribe and collect rates, fees and charges for the services and facilities of AMP during each fiscal year that will be at least sufficient to yield:

Adjusted Annual Revenues for such fiscal year at least equal to the sum of the following for such fiscal year:

a. Operating and Maintenance Cost.
b. Adjusted Annual Debt Service.
c. All other payments required to meet any other obligations of AMP which are charges, liens and encumbrances upon or payable from the Electric System Revenue Fund, including all amounts owed to any issuer of a Qualified Reserve Fund Credit Instrument then in effect and deposited in the Common Reserve Account under the terms of such Qualified Reserve Fund Credit Instrument and all amounts owing under subordinate debt, and Adjusted Annual Net Revenues for such fiscal year equal to at least 110% of Adjusted Annual Debt Service for such fiscal year.

If any event of default shall occur, then, and in each and every such case during the continuance of such event of default, the trustee may, and shall at the written direction of the owners of not less than a majority in aggregate principal amount of the bonds at the time outstanding, upon notice in writing to Alameda Municipal Power, declare the principal of all of the bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and shall be immediately due and payable, anything in the indenture or in the bonds contained to the contrary notwithstanding.

C. Debt Service Requirements

Annual debt service requirements for AMP's revenue bonds, loan from City of Alameda and leases are as follows:

For The Year Ending June 30	Principal	Interest	Total
2026	$1,935,000	$659,954	$2,594,954
2027	2,060,000	529,777	2,589,777
2028	2,195,000	406,657	2,601,657
2029	2,305,000	298,800	2,603,800
2030	2,410,000	183,675	2,593,675
2031	2,535,000	60,206	2,595,206
Total	$13,440,000	$2,139,069	$15,579,069

NOTE 5 – TRANSACTIONS WITH THE CITY OF ALAMEDA

Effective July 1, 2017, and each year thereafter, the City Charter states that AMP shall annually transfer to the City, the amount of $3,700,000 plus an adjustment for inflation, minus any deduction for the amount of any exemptions granted by the AMP Board pursuant to Article XII, Section 12-6, subdivision (d) of the City Charter, in twelve equal monthly installments. As of June 30, 2025 and 2024, $4,513,000 and $4,382,000 was transferred to the City's General Fund.

Alameda Municipal Code provides that AMP pays the City an annual amount equal to one percent of the net book value of AMP's utility plant in service at the previous fiscal year end. AMP paid $1,652,000 and $1,621,000 in lieu of taxes to the City during the fiscal years ended June 30, 2025 and 2024, respectively.

Disbursements by AMP to the City for services provided by the City for the years ended June 30, 2025 and 2024 were $4,513,000 and $4,382,000, respectively. Utility taxes collected by AMP and remitted to the City's General Fund for the years ended June 30, 2025 and 2024 were $5,108,776 and $5,168,433, respectively. Amounts payable to the City as of June 30, 2025 and 2024 were $2,844,553 and $0, respectively.

Billings of electricity to the City for the years ended June 30, 2025 and 2024 were $2,623,417 and $2,533,404, respectively.

NOTE 6 – DEFINED BENEFIT PLAN

A. CalPERS Miscellaneous Employees Plan

Plan Description – Substantially all City employees, including AMP employees, are eligible to participate in the City's Miscellaneous Plan offered by California Public Employees Retirement System (CalPERS), an agent multiple employer defined benefit pension plan which acts as a common investment and administrative agent for its participating member employers. CalPERS provides retirement and disability benefits, annual cost of living adjustments and death benefits to plan members, who must be public employees and beneficiaries. AMP only has miscellaneous employees that participate in the City of Alameda's separate Miscellaneous Employee Plan (all employees excluding Police and Fire). The City allocates a portion of the net pension liability, net pension expense, and related deferred inflows and outflows of resources to AMP on a cost-sharing basis. Benefit provisions under the Plan is established by State statute and City resolution. Benefits are based on years of credited service, equal to one year of full-time employment. Funding contributions for the Plan are determined annually on an actuarial basis as of June 30 by CalPERS; the City must contribute these amounts. CalPERS issues publicly available reports that include a full description of the pension plans regarding benefit provisions, assumptions and membership information can be found on the CalPERS website.

Benefits Provided – CalPERS provides retirement and disability benefits, annual cost of living adjustments and death benefits to plan members, who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full-time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after 10 years of service. The death benefit is one of the following; the Basic Death Benefit, the 1957 Survivor Benefit, or the Optional Settlement 2W Death Benefit. The cost of living adjustments for each plan are applied as specified by the Public Employees' Retirement Law.

NOTE 6 – DEFINED BENEFIT PLAN (Continued)

The Plans' provisions and benefits in effect at June 30, 2025 and 2024, are summarized as follows:

	Classic	PEPRA
Hire Date	Prior to January 1, 2013	On or after January 1, 2013
Formula	2% @55	2% @62
Benefit Vesting Schedule	5 years of service	5 years of service
Benefit Payments	monthly for life	monthly for life
Retirement Age	50-67+	50-67+
Monthly benefits, as a % of annual salary	1.426% to 2.418%	1.000% to 2.500%
Required employee contribution rates	8.868%	8.750%
Required employer contribution rates	9.100%	10.970%
Required UAL contribution	$2,207,301	

Contributions – Section 20814(c) of the California Public Employees' Retirement law requires that the employer contribution rates for all public employers are determined on an annual basis by the actuary and shall be effective on the July 1 following notice of a change in rate. Funding contributions for the Plan are determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate 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. AMP is required to contribute the difference between the actuarially determined rate and the contribution rates of employees. Employer contribution rates may change if plan contracts are amended. Payments made by the employer to satisfy contribution requirements that are identified by the pension plan terms as plan member contribution requirements are classified as plan member contributions. Employer contribution rates for the fiscal years ended June 30, 2025 and 2024 were 8.868 percent for the Classic Plan Members and 9.10 and 10.970 percent for the PEPRA Plan members.

Employee contribution rates for the fiscal years ended June 30, 2025 and 2024 were 8.868 percent for the Classic Plan Members and 8.75 and 8.25 percent for the PEPRA Plan members. AMP's proportionate share of the City's contributions to the miscellaneous plan was $3,372,606 and $3,143,794 for the years ended June 30, 2025, and 2024, respectively.

B. Pension Liability, Pension Expense and Deferred Outflows/Inflows of Resources Related to Pensions

As of June 30, 2025, and 2024, AMP reported a net pension liability of $24,993,984 and $26,538,237, respectively for its proportionate share of the City's net pension liability.

The net pension liability of the Plan was measured as of June 30, 2024 and 2023, and the total pension liability for the Plan used to calculate the net pension liability was determined by an actuarial valuation as of June 30, 2023 and 2022. AMP's proportion of the City's net pension liability was based on AMP's FY 2024 contributions to the City's pension plan relative to the total contributions of the City as a whole. AMP's proportionate share of the City's net pension liability for the Plan as of the June 30, 2024, and 2023 measurement dates was 27.17 percent and 27.78 percent, respectively.

NOTE 6 – DEFINED BENEFIT PLAN (Continued)

For the years ended June 30, 2025, and 2024, AMP recognized pension expense of $3,532,086 and $5,532,822, respectively. AMP reported deferred outflows of resources and deferred inflows of resources related to pension from the following sources as of June 30:

	2025	
	Deferred Outflows of Resources	Deferred Inflows of Resources
Employer contributions paid by AMP subsequent to measurement date	$3,372,606	
Differences between expected and actual experiences	581,404	
Change in assumptions		
Differences due to change in proportion		($672,149)
Net differences between projected and actual earnings on pension plan investments	958,174	
Total	$4,912,184	($672,149)

	2024	
	Deferred Outflows of Resources	Deferred Inflows of Resources
Employer contributions paid by AMP subsequent to measurement date	$3,143,794	
Differences between expected and actual experiences	165,622	($83,491)
Change in assumptions	384,593	
Differences due to change in proportion	320,436	
Net differences between projected and actual earnings on pension plan investments	3,143,777	
Total	$7,158,222	($83,491)

The amount of $3,372,606 reported as deferred outflows of resources related to pensions, resulting from AMP's contributions to the City's pension plan subsequent to the measurement date, will be recognized as a reduction of the net pension liability in the year ended June 30, 2026. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized as pension expense as follows as of June 30:

2025		2024	
Year ended June 30,		Year ended June 30,	
2026	$275,947	2025	$1,437,833
2027	1,987,297	2026	191,207
2028	(323,595)	2027	2,224,284
2029	(400,071)	2028	77,613
Total	$1,539,578	Total	$3,930,937

NOTE 6 – DEFINED BENEFIT PLAN (Continued)

Actuarial Assumptions – AMP's proportion of the City's total miscellaneous plan pension liability as of the June 30, 2024, and 2023, measurement date were determined using the following assumptions:

Valuation Date	July 1, 2023	June 30, 2022
Measurement Date	June 30, 2024	June 30, 2023
Actuarial Cost Method	Entry Age Actuarial Cost Method	
Actuarial Assumptions:		
Investment Rate	6.90%	7.00%
Discount Rate	6.90%	6.90%
Inflation Rate	2.30%	2.50%
Payroll Growth	2.80%	2.75%
Projected Salary Increase	(1)	(1)
Mortality	Derived using CalPERS' Membership data for all funds (2)	

(1) Depending on age, service and type of employment.
(2) The mortality table used was developed based on CalPERS' specific data.

The underlying mortality assumptions and all other actuarial assumptions used in the June 30, 2023 valuation were based on the results of a November 2021 actuarial experience study for the period of 2001 to 2019. Further details of the Experience Study can be found on the CalPERS website at: www.calpers.ca.gov under Forms and Publications.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class.

In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations. Using historical returns of all the funds' asset classes, expected compound (Geometric) returns were calculated over the next 20 years using a building-block approach. The expected rate of return was then adjusted to account for assumed administrative expenses of 10 basis points.

NOTE 6 – DEFINED BENEFIT PLAN (Continued)

The tables below reflect long-term expected real rate of return by asset class. The rate of return is calculated using the capital market assumptions applied to determine the discount rate and asset allocation.

2025		
Asset Class (1)	Assumed Asset Allocation	Real Return 1,2
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%
Total	100.00%	

(1) An expected inflation of 2.30% used for this period.
(2) Figures are based on the 2021 Asset Liability Management study.

2024		
Asset Class (1)	Assumed Asset Allocation	Real Return 1,2
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%
Total	100%	

(1) An expected inflation of 2.30% used for this period.
(2) Figures are based on the 2021 Asset Liability Management study.

NOTE 6 – DEFINED BENEFIT PLAN (Continued)

Discount Rate – The discount rate used to measure the total pension liability was 6.90% for the Plan. The projection of cash flows used to determine the discount rate for the Plan assumed contributions from all plan members in the Public Employees Retirement Fund (PERF) will be made at the current member contribution rates and that contributions from employers will be made at statutorily required rates, actuarially determined. Based on those assumptions, Plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Sensitivity of AMP's proportionate share of the City's Miscellaneous Plan Net Pension Liability to Changes in the Discount Rate – The following presents AMP's proportionate share of the City's Miscellaneous Plan net pension liability, calculated using the discount rate of 6.90 percent and 6.90 percent for the Plan as of June 30, 2025 and June 30, 2024, respectively, as well as what AMP's proportionate share of the City's Miscellaneous Plan net pension liability would be if it were calculated using a discount rate that is 1-percentage point lower or 1 percentage point higher than the current rate:

	2025	2024
1% Decrease	5.90%	5.90%
Net Pension Liability	$36,226,768	$38,261,712
Current Discount Rate	6.90%	6.90%
Net Pension Liability	$24,993,984	$26,538,237
1% Increase	7.90%	7.90%
Net Pension Liability	$14,243,503	$16,459,187

Pension Plan Fiduciary Net Position – Detailed information about the City's Miscellaneous Plan net pension liability is available in the City's separately issued Annual Comprehensive Financial Report. The City's financial statements may be obtained by contacting the City of Alameda's Finance Department. That report may be obtained on the internet at alamedaca.gov. Detailed information about the pension plan's fiduciary net position is available in the separately issued CalPERS financial reports.

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS

A. City of Alameda Other Post-Employment Benefit Plan

Plan Description – The City of Alameda provides medical and dental benefits to retirees as specified below under the City of Alameda Other Post-Employment Benefit (OPEB) Plan, an agent multiple-employer defined benefit health care plan. The City is responsible for establishing and amending the funding policy of the Plan.

The City established an irrevocable trust with Public Agency Retirement Services (PARS) to fund its retiree health benefits. Contributions to the trust are made annually according to the City's OPEB funding policy.

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS (Continued)

The City is the Plan administrator, while PARS administers the investment trust. The City's OPEB Plan does not issue separate financial statements. PARS issues a separate annual financial report and copies of the report may be obtained by writing to PARS at 4350 Von Karman Ave., Suite 100, Newport Beach, California, 92660.

Benefits provided – The following is a summary of Plan eligibility requirements and benefits by employee group as of June 30, 2025:

Eligibility requires retiring from the City under CalPERS typically on or after age 50 (52 for PEPRA employees) with at least 5 years of CalPERS service or disability retirement.

The City's contribution for medical coverage for Miscellaneous employees is the Public Employees' Medical and Hospital Care Act (PEMHCA) minimum required contribution (MRC) - $158 per month in 2025.

As of June 30, 2025, and 2024, the total amount of benefits paid by AMP were $71,647 and $86,947, respectively.

B. OPEB Liability, OPEB Expense and Deferred Outflows/Inflows of Resources Related to OPEB

As of June 30, 2025, and 2024, AMP reported a net OPEB liability of $958,114 and $1,002,488, respectively, for its proportionate share of the City's net OPEB liability.

The net OPEB liability of the Plan was measured as of June 30, 2025, and the net OPEB liability for the Plan used to calculate the net OPEB liability was determined by an actuarial valuation as of June 30, 2023. AMP's proportion of the City's net OPEB liability was based on AMP's FY 2023 contributions to the City's OPEB plan relative to the total contributions of the City as a whole. AMP's proportionate share of the City's net OPEB liability for the Plan as of June 30, 2025, and 2024 measurement dates were 2.22 percent.

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS (Continued)

For the years ended June 30, 2025, and 2024, AMP recognized OPEB expense of ($63,956) and ($142,623) respectively. At June 30, 2025 and 2024, AMP reported deferred outflows of resources and deferred inflows of resources related to OPEB from the following sources:

	2025	
	Deferred Outflows of Resources	Deferred Inflows of Resources
Differences between expected and acturial experiences on liability	$93,230	($64,046)
Net differences between projected and actual earnings on plan investments		
Changes in assumptions	29,997	(208,493)
Total	$123,227	($272,539)

	2024	
	Deferred Outflows of Resources	Deferred Inflows of Resources
Differences between expected and acturial experiences on liability	$23,336	($127,775)
Net differences between projected and actual earnings on plan investments	1,163	
Changes in assumptions	59,518	(219,590)
Total	$84,017	($347,365)

Amounts reported as deferred outflows of resources and deferred inflows of resources related to OPEB will be recognized as OPEB expense as follows:

2025		2024	
Year ended June 30,	Annual Amortization	Year ended June 30,	Annual Amortization
2026	($161,648)	2025	($120,421)
2027	7,688	2026	(159,078)
2028	3,323	2027	10,258
2029	(2,570)	2028	5,893
2030	3,895	Total	($263,348)
Total	($149,312)		

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS (Continued)

Actuarial Assumptions – AMP's proportion of the City's net OPEB liability in the June 30, 2023 actuarial valuations were determined using the following actuarial assumptions:

	2025	2024
Actuarial Cost Method	Entry-Age Normal Cost Method, level percent of pay	Entry-Age Normal Cost Method, level percent of pay
Actuarial Assumptions:		
Valuation Date	June 30, 2024	June 30, 2022
Measurement Date	June 30, 2025	June 30, 2024
Discount Rate	5.92%	5.07%
Inflation	2.30%	2.30%
Investment Rate of Return	6.50%	6.07%
Payroll Growth	2.80%, plus merit increases	2.88%, plus merit increases
Healthcare Cost Trend Rate:		
PPO	6.80%, trending down to 4.04%	6.40%, trending down to 3.73%
HMO	6.80%, trending down to 4.04%	6.40%, trending down to 3.73%

Mortality assumptions were based on the mortality rates under the CalPERS most recent pension experience study projected fully generational Scale MP-2014 modified to converge to ultimate rates in 2022.

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS (Continued)

The long-term expected real rate of return by asset class. The rate of return was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of OPEB plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. Best estimates of arithmetic real rates of return for each major asset class included in the OPEB plan's target asset allocation as of June 30, 2025 are summarized in the following table:

	2025	
Asset Class	Target Allocation	Long-Term Expected Real Rate of Return
Moderate Plus		
Equity	45.00%	
Fixed income	50.50%	
Real Estate	2.50%	
Cash	2.00%	
Total	100%	6.5%

	2024	
Asset Class	Target Allocation	Long-Term Expected Real Rate of Return
Moderate Plus		
Equity	48.00%	5.14%
Fixed income	45.00%	2.36%
Real Estate	2.00%	3.79%
Cash	5.00%	0.77%
Total	100%	

Discount rate – The discount rate used to measure the net OPEB liability was 5.92 percent, based on a blended rate of asset expected rates of return using the average of three 20 year municipal bond rate indices: S&P Municipal Bond 20 Year High Grade Rate Index, Bond Buyer GO 20-Bond Municipal Bond Index, and Fidelity 20 Year GO Municipal Bond Index.

Change in assumptions – For the measurement date of June 30, 2025, the discount rate increased from 5.07 percent to 5.92 percent and the healthcare cost trend rates were decreased from 6.90 percent to 6.80 percent.

NOTE 7 – POST EMPLOYMENT HEALTH CARE BENEFITS (Continued)

Sensitivity of AMP's proportionate share of the City's Net OPEB Liability to Changes in the Discount Rate – The following presents AMP's proportionate share of the City's net OPEB liability, calculated using the investment rate of return of 6.07 percent for the Plan, as well as what AMP's proportionate share of the City's net OPEB liability would be if it were calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	2025		
	1% decrease (4.92%)	Discount Rate (5.92%)	1% Increase (6.92%)
Net OPEB Liability	$1,067,709	$958,114	$865,478

	2024		
	1% decrease (4.07%)	Discount Rate (5.07%)	1% Increase (6.07%)
Net OPEB Liability	$1,129,579	$1,002,488	$896,768

Sensitivity of AMP's proportionate share of the City's Net OPEB Liability to Changes in the Healthcare Cost Trend Rate – The following presents AMP's proportionate share of the City's net OPEB liability, calculated using the healthcare cost trend rate of 6.8 (2025)/6.40 (2024) percent for the Plan, as well as what AMP's proportionate share of the City's net OPEB liability would be if it were calculated using a healthcare cost trend rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	2025		
	(5.80% HMO/5.80% PPO)	(6.80% HMO/6.80% PPO)	(7.80% HMO/7.80% PPO)
Net OPEB Liability	$872,746	$958,114	$865,478

	2024		
	(5.40% HMO/5.40% PPO)	(6.40% HMO/6.40% PPO)	(7.40% HMO/7.40% PPO)
Net OPEB Liability	$876,108	$1,002,488	$1,153,897

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA)

A. General

AMP participates in joint ventures through Joint Powers Authorities (JPAs) established under the Joint Exercise of Powers Act of the State of California. As separate legal entities, these JPAs exercise full powers and authorities within the scope of the related Joint Powers Agreement, including the preparation of annual budgets, accountability for all funds, the power to make and execute contracts and the right to sue and be sued. Obligations and liabilities of the JPAs are not those of AMP and the other participating entities unless assumed by them.

Each JPA is governed by a board consisting of representatives from each member agency. Each board controls the operations of its respective JPA, including selection of management and approval of operating budgets, independent of any influence by member agencies beyond their representation on the board.

The JPAs are discussed in this note and in Note 9.

AMP is a member of NCPA, a joint powers agency which operates under a joint powers agreement among fifteen (15) public agencies (AMP, BART, Biggs, Gridley, Healdsburg, Lompoc, Palo Alto, Ukiah, Lodi, Port of Oakland, Redding, Roseville, Shasta Lake, Silicon Valley Power, Truckee-Donner PUD). Turlock Irrigation District withdrew from NCPA on April 1, 2011. The City of Shasta Lake was added as a new member in 2016. The purpose of NCPA is to use the combined strength of its members to purchase, generate, sell and interchange electric energy and capacity through the acquisition and use of electrical generation and transmission facilities, as well as to optimize the use of those facilities and the member's position in the industry. Each agency member has agreed to fund a pro rata share of certain assessments by NCPA and certain members have entered into take-or-pay power supply contracts with NCPA. While NCPA is governed by its members, none of its obligations are those of its members unless expressly assumed by them.

Amounts paid by AMP, net of refunds, to NCPA during the fiscal years ending June 30, 2025 and 2024 for purchased power were $32,416,136 and $35,696,806 respectively. Additionally, purchased power was reduced by a refund of $409,776 and $503,269 for power exchange distribution and budget settlement monies returned to the NCPA General Operating Reserve (GOR), for the fiscal years ended June 30, 2025 and 2024, respectively.

AMP receives no income from NCPA and does not participate in all of its projects. Further, NCPA does not measure or determine AMP's equity in NCPA as a whole. NCPA reports only AMP's share of its General Operating Reserve, comprised of cash and investments, and AMP's share of those projects in which AMP is a participant. These amounts are reflected in the financial statements as Investment in Joint Venture - Share of Certain NCPA Projects and Reserve.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

The changes in AMP's share in NCPA projects and reserve are set forth below:

	June 30, 2025	June 30, 2024
Beginning balance	$7,191,054	$6,231,541
Increase (decrease) in equity in NCPA projects	1,556,142	959,513
Ending balance	$8,747,196	$7,191,054

AMP's interest in NCPA Projects and Reserve, as computed by NCPA, is set forth below:

	June 30, 2025	June 30, 2024
General Operating Reserve	$2,420,548	$1,501,035
Share of Scheduling Coordination Balancing Account	2,859,807	2,767,348
Share of Congestion Revenue Rights (CRR)	403,119	435,483
Share of ISO EAL Deposit	1,796	1,712
Associated Member Services	155,974	119,458
Market Purchase Program (MPP) Security Deposit	526,422	12,694
	6,367,666	4,837,730
Net book value of amounts contributed to fund		
Alameda Municipal Power's share of NCPA Power:		
Geothermal Projects/Power Line	2,370,806	1,452,837
Calaveras Hydroelectric Project	281,616	590,136
Combustion Turbine Project No. 1	10,168	162,797
Combustion Turbine Project No. 2	(283,060)	147,554
	$8,747,196	$7,191,054

The General Operating Reserve represents AMP's portion of funds which resulted from the settlement in prior years of issues with financial consequences and reconciliations of several prior years' budgets for programs. These funds are available on demand and earn interest.

Members of NCPA may participate in an individual project of NCPA without obligation for any other project. Member assessments collected for one project may not be used to finance other projects of NCPA without the member's permission.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

B. Projects in which AMP is a Participant

Geothermal Projects – A power purchase agreement with NCPA obligates AMP for 18.31469 percent of the debt service and the operating costs for two geothermal steam powered generating plants, Plant Number 1 and Plant Number 2, located in the Geysers area in Northern California. In conjunction with these payments, AMP is entitled to receive 16.8825 percent of the output from these facilities. NCPA continues to pursue alternatives for improving and extending steam field reservoir performance, including supplemental water reinjection, plant equipment modifications, and changes in operating methodology. NCPA has increased steam production in the vicinity of reinjection wells and has evaluated a number of alternatives to increase water reinjection at strategic locations.

Calaveras Hydroelectric Project – NCPA contracted to finance, manage, construct, and operate Hydroelectric Project Number One for the licensed owner, Calaveras County Water District. In exchange, NCPA has the right to the electric output of the project for 50 years starting in February 1982 and also has an option to purchase power from the project in excess of the District's requirements for the subsequent 50 years, subject to regulatory approval. Debt service payments to NCPA began in February 1990 when the project was declared substantially complete and power was delivered to the participants. AMP is entitled to receive 10.0 percent of output from facility. The debt obligation increased to 11.582% as other members have opted out and a reallocation was done for the remaining members.

Combustion Turbine Project No. 1 – In October 1984, NCPA financed a five-unit, l25-megawatt combustion turbine project. The project, built in three member cities including Alameda, began full commercial operation in June 1986 and provides reserve and peaking power. During August 2010, phase two of the first amendment to the NCPA power purchase agreement finalized the transfer of ownership of two NCPA electricity generating units to the City of Roseville due to a misalignment of ISO control areas. The transfer reduced the generation output of the project to 74 MW, and increased the entitlement share to 21.82 percent. Although AMP's project percentage share increases, its resulting generating capacity entitlement remains constant at 16.05 MW.

Combustion Turbine Project No. 2 (Steam Injected Gas Turbine Project) – AMP is a participant in NCPA's 49.8 megawatt Steam Injected Gas Turbine (STIG) project which was built under turnkey contract near the City of Lodi and declared substantially complete on April 23, 1996. In 2010, the NCPA issued 2010 Refunding Series A Bonds for $55,120,000 for the purpose of providing funds to refund all of the Refunded 1999 Bonds, to fund a deposit to the 2010 Series debt service reserve account and to pay cost of issuance of the 2010 Series A Bonds. Under the NCPA power purchase agreement, AMP is obligated to pay 19 percent of the debt service for the STIG project.

On December 20, 2019, NCPA issued Capital Facilities Revenue Bonds, 2019 Refunding Series A, in the amount of $20,450,000 with an average interest rate of 5.0% to refund $25,450,000 of outstanding Capital Facilities Revenue Bonds, 2010 Refunding Series A with an average interest rate of 5.1249%. The net proceeds were used to purchase US government securities. Those securities were deposited in an irrevocable trust with an escrow agent to provide for all future debt service payments on the old bonds. As a result, the old bonds are considered defeased. The outstanding 2010 Series A Bonds were called for redemption on February 1, 2020.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

On April 2, 2019, NCPA issued Hydroelectric Project Number One Revenue Bonds, 2019 Refunding Series A, in the amount of $39,250,000 with an average interest rate of 4.9126% to refund $52,845,000 of outstanding Hydroelectric Project Number One Revenue Bonds, 2010 Refunding Series A with an average interest rate of 4.9003%. The net proceeds were used to purchase US government securities. Those securities were deposited in an irrevocable trust with an escrow agent to provide for all future debt service payments on the old bonds. As a result, the old bonds are considered defeased.

AMP's participation in procurement of natural gas for fuel for existing and new combustion turbine units was approved in 1993. Although there is currently no additional debt financing, AMP and NCPA have committed to long-term payments for gas transmission pipeline capacity, and entered a purchase contract for natural gas. AMP is obligated to pay 19.0 percent.

NCPA's notes from direct placement contain provisions that in an event of default, outstanding amounts become immediately due if (1) NCPA is unable to pay the principal or interest when due, (2) files bankruptcy or becomes insolvent, or (3) S&P issues a downgrade below "BBB-".

NCPA outstanding revenue bonds contain provisions that in the event of a participant default, the project entitlement percentage of each non-defaulting project participant will increase on a prorated basis up to a maximum of 25% for Hydroelectric, Geothermal and Capital Facilities projects and 35% for the Lodi Energy Center project. AMP does not participate in the Lodi Energy Center project but would be obligated under the other projects.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

As of June 30, 2025, AMP's share of long-term debt for the Geothermal, Hydroelectric and Capital Facilities Projects are set forth below:

		Total					AMP	
	Final Maturity	Balance July 1, 2024	Additions	Retirements	Balance June 30, 2025	Current Portion	AMP's Obligation (a) %	$
Geothermal Project								
2016A	7/1/2024	$3,425,000		$3,425,000			16.8825%	
Total Geothermal Project		3,425,000		3,425,000				
Hydroelectric Project								
2012A&B	7/1/2032	7,120,000		7,120,000			10.0000%	
2018A&B (a)	7/1/2025	14,245,000		14,245,000			11.5821%	
2022A	7/1/2032	120,300,000		3,260,000	$117,040,000	$9,985,000	10.0000%	$11,704,000
2022B	7/1/2027	8,060,000		2,795,000	5,265,000	2,450,000	10.0000%	526,500
Unamortized premium	7/1/2025	24,392,133		2,838,103	21,554,030		10.0000%	
Total Hydroelectric Project		174,117,133		30,258,103	143,859,030	12,435,000		12,230,500
Capital Facilities (STIG)								
2019A	7/1/2025	4,815,000		4,815,000			19.0000%	
Unamortized premium		162,567		162,567			19.0000%	
Total Capital Facilities		4,977,567		4,977,567				
Total Long-Term Debt		$182,519,700		$38,660,670	$143,859,030	$12,435,000		$12,230,500

NCPA Geothermal (2009A & 2016A) and Hydroelectric bonds pay principal July 1. Geothermal 2012A bonds pay principal both January 1 and July 1.
(a) AMP's share is 10%, the above reflects the other member opt out allocation %.
NCPA Capital Facilities bond pay principal August 1.

Defeased Debt - Various bond refundings were undertaken to defease debt and realize future debt service savings. Debt was defeased by using the proceeds of the refunding issues and other available monies to irrevocably place in trust cash and US Gov't securities, which together with interest earned thereon, will be sufficient to pay both the interest and the appropriate maturity or redemption value of the refunded bonds as required.

Graeagle Hydroelectric Project – AMP's participation in this small hydroelectric project was approved in 1993. Although this project does not involve any financing, it does involve a long-term contractual commitment to purchase the power produced by the project. AMP receives 100 percent of the power output from this small 440 kilowatt hydroelectric project.

Western Area Power Administration – AMP has an allocation of power from the Federal Central Valley Project generating resources contracted through the U.S. Department of Energy's Western Area Power Administration. This allocation has been temporarily assigned to NCPA for scheduling and delivery to AMP. AMP pays 1.08075 percent of the base resource costs and receives that same amount of the base resource, power generated in one federal fiscal year.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

Other Power Purchase Agreements – AMP has also entered into a number of other power purchase agreements which are scheduled by or through NCPA.

Highwinds Project Power Purchase

In December 2004, AMP entered into a long-term power purchase agreement with PPM Energy, Inc. for power supplied by the Highwinds Project in Solano County, California. In 2008, Iberdrola Renewables succeeded PPM Energy as the seller counterparty for this power purchase agreement. AMP receives 6.17 percent of the output of the 162 megawatt project (nameplate rating) – 10 megawatts – as delivered through June 30, 2028.

Landfill Gas Projects Power Purchase

Since 2004, AMP has entered into five long-term power purchase agreements for power supplied by multiple generating facilities, of which only four are still active. These facilities utilize combustible gaseous emissions from landfills, located in or near the San Francisco Bay area to create power. AMP began receiving nearly 3.45 megawatts of base-load power from each of the first two facilities in 2004 and early 2006. An additional 5.2 megawatts of base-load output were added to AMP's portfolio in April 2009 when the Ox Mountain facility commenced operation. An additional 1.9 megawatts of power were added to AMP's portfolio as the Keller Canyon facility commenced base-load operation in August 2009. The final landfill facility, Butte, commenced operation at the end of 2012.

Silicon Valley Power Renewable Power Purchase

Since 2018, AMP has entered into a long-term power purchase agreement with Silicon Valley Power for winter-only, renewable power. Silicon Valley Power supplies AMP with 10MW of baseload renewable energy production from various renewable energy generators for the months of October through February.

California Electric Industry Restructuring – In September 1996, the California State legislature signed into law Assembly Bill 1890 (AB 1890) deregulating the electric power supply market and restructuring the electric power industry in California. While the majority of the legislation was directed at investor-owned utilities (IOUs), AMP and other California publicly owned utilities were greatly affected by the restructuring of markets and the ensuing wild fluctuations in prices that resulted from a deficiency in generating capacity and an immature and flawed market structure. Because AMP has its own generating resources and is not heavily dependent on the wholesale market to purchase power, it was not significantly impacted by these price swings.

In April 2008, the California Independent System Operator (CAISO) launched a new wholesale market structure in the state which is referred to as the Market Redesign and Technology Upgrade (MRTU).

While MRTU features a day-ahead energy market with a nodal locational marginal price calculation, both load and resources are currently priced as aggregated pricing. The MRTU initiative has introduced new risks and uncertainties for AMP because the Federal Energy Regulatory Commission (FERC) continues requiring CAISO to implement a disaggregated market that will negatively affect AMP because it is in a transmission constrained location. To establish the extent of the risk and identify its impact to rates, AMP continues to monitor changes that CAISO makes to its market structure and operations.

NOTE 8 – NORTHERN CALIFORNIA POWER AGENCY (NCPA) (Continued)

NCPA plays an active role in protecting members' contractual rights in Federal Energy Regulatory Commission (FERC), California Public Utilities Commission (CPUC), and other legislative/regulatory proceedings. Priorities related to industry restructuring include the preservation of local control authority for publicly owned utilities, assuring open and fair access to wholesale markets and the transmission grid, and maintaining members' preference access to power from the Central Valley Project and Western Area Power Administration.

NCPA Financial Information – NCPA's financial statements can be obtained from NCPA, 651 Commerce Drive, Roseville, California 95678.

NOTE 9 – TRANSMISSION AGENCY OF NORTHERN CALIFORNIA (TANC)

AMP is a member of a joint powers agreement with fifteen other entities in TANC. TANC's purpose is to provide electrical transmission or other facilities for the use of its members. While governed by its members, none of TANC's obligations are those of its members unless expressly assumed by them. The California-Oregon Transmission Project (COTP) is one of three high voltage transmission lines connecting Oregon and California. The 500 kV line is able to transmit 1,600 MW/h of electricity. The COTP participants include the Transmission Agency of Northern California, Western, PG&E, City of Redding, Carmichael Water District, and the San Juan Water District. Currently, the COTP provides a transmission path for resources that is outside of the CAISO balancing authority. According to the 1985 Project Agreement with TANC for the development of the COTP and subsequent related project agreements, AMP is obligated to pay its share of the project's costs, including debt service and is entitled to the use of a percentage of the project's transmission or transfer capacity.

AMP’s entitlement share on COTP is 1.2274 percent and AMP is obligated to pay 1.33 percent of the project’s operating costs.

AMP is obligated to pay 1.33 percent of TANC's debt-service related to the California – Oregon Transmission Project (COTP). AMP’s share on the 2009 Series A bonds is 1.4496 percent. AMP is not obligated for any portion of the 2009 Series B bonds.

These obligations provide AMP with a COTP transfer capability of 17.05 MW. AMP is also obligated to pay for a portion of the debt associated with the South of Tesla transmission which is provided under an agreement between TANC and Pacific Gas & Electric Company.

NOTE 9 – TRANSMISSION AGENCY OF NORTHERN CALIFORNIA (TANC) (Continued)

In May 2009, TANC issued $67.0 million of tax-exempt 2009 Series A bonds and $61.8 million of taxable 2009 Series B bonds. The proceeds of the Series A bonds were used to retire a bank loan that refinanced $30.3 million of TANC's tax-exempt commercial paper and also to refund $34.7 million of TANC's 2003 Series C Auction Rate Securities. The proceeds of the Series B bonds were used to retire a bank loan that refinanced $56.3 million of TANC's taxable commercial paper. The 2009 refunding increased future aggregate debt service payments by $19.3 million, but resulted in a total economic gain of $6.5 million, the difference between present value of the old and new debt service payments. TANC has issued Revenue Bonds for $435,790,000 and eliminated its obligations for the Tax Exempt Commercial Paper notes. As of June 30, 2025 and 2024, AMP's share of this debt is $0 and $0, respectively.

As of July 1, 2014, AMP and other NCPA members executed a multiparty Long-Term Layoff Agreement (the Agreement) that laid off their participating percentage share of the COTP to other TANC participants namely the Sacramento Municipal Utility District, the Turlock Irrigation District, and Modesto Irrigation District, for twenty-five (25) years with the option to extend for an additional five years upon all parties approval. During the layoff period AMP and other NCPA members will not pay any debt service or operating costs. During the term of the Agreement, AMP would relinquish its voting rights on all short-term decisions and actions at TANC related to the COTP.

In 2016, TANC issued $173.9 mission of tax-exempt 2016 Series A Revenue Refunding Bonds. The proceeds of the bonds were used to refund the certain outstanding bonds issued by TANC to finance or refinance a portion of the costs of the California – Oregon Transmission Project, fund the costs of terminating in full certain interest rate swap agreements relating to the variable rate Refunded Bonds, and fund a debt service reserve account for the 2016A bonds, and pay costs of the issuance of the 2016A Bonds. The 2016 Series A “small member” debt portion is $2,517,565. AMP is obligated to pay $52,301, or 2.104 percent of that debt.

TANC Financial Information - TANC's financial statements can be obtained from TANC, P.O. Box 15129, Sacramento, California 95851 or from their website at http://www.tanc.us/about-tanc/financials.

NOTE 10 – RISK MANAGEMENT

AMP, as a department of the City, participates in the City's risk management program. The City manages risk by participating in two public entity risk excess pools described below and by retaining certain risks.

Public entity risk pools are formally organized and separate entities established under the Joint Exercise of Powers Act of the State of California. As separate legal entities, those entities exercise full powers and authorities within the scope of the related Joint Powers Agreements including the preparation of annual budgets, accountability for all funds, the power to make and execute contracts and the right to sue and be sued. Each risk pool is governed by a board consisting of representatives from member municipalities. Each board controls the operations of the respective risk pool, including selection of management and approval of operating budgets, independent of any influence by member municipalities beyond their representation on that board. Obligations and liabilities of these risk pools are not AMP's or the City's responsibility.

NOTE 10 – RISK MANAGEMENT (Continued)

AMP has not reduced its risk pool coverage from the prior year. Furthermore, settlements have not exceeded insurance coverage for the past three fiscal years.

A. Risk Coverage

The City is a member of the Local Agency Workers' Compensation Excess Joint Powers Authority (LAWCX) which covers workers' compensation claims up to $5,000,000 and provides additional coverage up to statutory limits. The City has a deductible or uninsured liability of up to $500,000 per claim. During the fiscal years ended June 30, 2025 and 2024, AMP contributed $152,829 and $152,617 for the coverage, respectively.

The contributions made to each risk pool equal the ratio of their respective payrolls to the total payrolls of all entities participating in the same layer of each program, in each program year. Actual surpluses or losses are shared according to a formula developed from overall loss costs and spread to member entities on a percentage basis after a retrospective rating.

The City is also a member of the California Joint Powers Risk Management Authority (CJPRMA), an excess risk-sharing pool providing general liability, auto liability, physical vehicle damage, property and boiler and machinery insurance coverage. For the liability policies, the Authority provides $40,000,000 in coverage subject to a self-insured retention limit of $500,000. The physical vehicle damage coverage covers both owned and leased vehicles valued at $25,000 or more, subject to a $10,000 deductible. With regard to the property and boiler and machinery coverage, the Authority provides “all risk” (excluding flood and quake) replacement cost coverage subject to a $25,000 deductible.

The following types of loss risks are covered by the above authority under the terms of their respective joint-powers agreements, through commercial insurance policies, and self-insured programs as follows:

Type of Coverage	Coverage Limits
Excess General Liability	$40,000,000
Pollution	5,000,000
Auto-Physical damage	10,000,000
Workers' Compensation	Statutory Limits
Property Coverage	400,000,000
Boiler & Machinery	100,000,000
Computer Software	Self-Insured
Terrorism	12,500,000
Aircraft Policy - Drones	5,000,000
Deadly Weapon Response Program	500,000

Financial statements for the workers’ compensation excess risk pool may be obtained from LAWCX, c/o Bickmore & Associates, 6371 Auburn Boulevard, Citrus Heights, California 95621. Financial statements for the liability/property excess risk pool may be obtained from CJPRMA, 3201 Doolan Drive, Suite 285, Livermore, California 94551.

NOTE 10 – RISK MANAGEMENT (Continued)

B. General Liability and Workers' Compensation Claims Payable

The Governmental Accounting Standards Board (GASB) requires municipalities to record their liability for uninsured claims and to reflect the current portion of this liability as an expenditure in their financial statements. As discussed above, AMP has coverage for such claims, but it has retained the risk for the deductible or uninsured portion of these claims. The change in general liability and workers' compensation claims liability, including claims incurred but not reported as estimated by the City's independent actuary, is based on historical trend information provided by its third-party administrators and was computed as follows at June 30:

	Worker's Compensation	General Liability	Total
Beginning balance as of July 1, 2022	$131,721	$988,356	$1,120,077
Change in liablity for current and prior fiscal year claims	(18,992)	(312,073)	(331,065)
Payments made on claims	49,348		49,348
Liability as of June 30, 2023	162,077	676,283	838,360
Change in liablity for current and prior fiscal year claims	(19,599)	159,390	139,791
Payments made on claims	50,230		50,230
Liability as of June 30, 2024	192,708	835,673	1,028,381
Change in liablity for current and prior fiscal year claims	(35,340)	(252,179)	(287,519)
Payments made on claims	(26,302)		(26,302)
Ending Balance as of June 30, 2025	131,066	583,494	714,560
Less Current Portion	131,066	30,727	161,793
Long-term porition		$552,767	$552,767

NOTE 11 – COMMITMENTS AND LEASE

A. Take -or- Pay Agreements

Under the terms of its NCPA and TANC joint venture agreements, AMP is liable for a portion of the bonded indebtedness issued by these agencies under take-or-pay or similar agreements, as discussed in Notes 8 and 9. AMP's estimated share of such debt outstanding at June 30, 2025 was $12,230,500 Under certain circumstances, AMP may also be responsible for a portion of the costs of operating these entities. Under certain circumstances, such as default or bankruptcy of other participants, AMP may also be liable to pay a portion of the debt of these joint ventures on behalf of the other participants. These "step up" provisions are generally capped at a 25 percent increase.

NOTE 11 – COMMITMENTS AND LEASE (Continued)

Take-or-Pay commitments expire upon final maturity of outstanding debt for each project. Final fiscal year debt expirations are as follows:

Project	Debt Expiration	Entitlement	Debt service %
NCPA - Calaveras Hydroelectric Project (NCHP)	Jul-2032	10.00000%	8.50173%

As discussed in Note 9, as of July 1, 2014, AMP and other NCPA members executed a multiparty Long-Term Layoff Agreement that laid off their participating percentage share of the COTP to other TANC participants.

A summary of AMP's "Take or Pay" contracts and related projects and its contingent liability for the debt service including principal and interest payments at June 30, 2025 is as follows:

Fiscal Year	NCHP	Total
2026	$1,332,261	$1,332,261
2027	1,638,369	1,638,369
2028	1,459,667	1,459,667
2029	1,498,500	1,498,500
2030	1,595,000	1,595,000
2031-2033	4,706,703	4,706,703
Total	$12,230,500	$12,230,500

B. Lease Agreement with 1835 Alameda Property, LLC

In March 2016, AMP entered into a property lease agreement with the 1835 Alameda Property, LLC for warehousing/distributing space. The lease terms for the agreement started on May 1, 2016 and will expire on April 30, 2031. The base rent is $24,700 per month. The monthly lease payments are increased annually in the amount of 3% every May 1. AMP recorded an initial lease liability and intangible right-to-use asset in the amount of $3,142,914, respectively, as of July 1, 2021. As of June 30, 2025, the balance of the lease liability was $2,099,837 and the value of the right-to-use asset was $3,142,914, and accumulated amortization was $1,208,473.

NOTE 11 – COMMITMENTS AND LEASE (Continued)

A summary of the lease transactions for the fiscal year ended June 30, 2025, are as follows:

	Balance June 30, 2024	Retirements	Balance June 30, 2025	Current Portion
Lease Liability				
1835 Alameda Property, LLC	$2,387,806	($287,969)	$2,099,837	$307,545
Total	$2,387,806	($287,969)	$2,099,837	$307,545

Annual principal and interest payments due on the lease are as follows:

For the Year Ended June 30	Principal	Interest	Total
2026	$307,545	$58,812	$366,357
2027	328,042	49,306	377,348
2028	349,496	39,172	388,668
2029	371,948	28,381	400,329
2030	395,437	16,902	412,339
2031	347,369	4,794	352,163
Totals	$2,099,837	$197,367	$2,297,204

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Required Supplementary Information
June 30, 2025

Alameda Municipal Power

Schedule of AMP's Proportionate Share of the
City's Miscellaneous Agent Multiple-Employer Plan Net Pension Liability
Last 10 Fiscal Years

Measurement Date	2025	2024	2023	2022	2021
AMP's proportion of the City's Net pension liability	27.17%	27.78%	27.67%	28.23%	32.00%
AMP's proportionate share of the City's net pension liability	$24,993,984	$26,538,237	$25,976,605	$14,247,182	$27,294,740
AMP's Covered payroll	$9,540,161	$8,428,246	$8,062,367	$9,412,682	$9,317,305
AMP's proportionate share of the City's net pension liability as a percentage of covered payroll	261.99%	314.87%	322.20%	151.36%	292.95%
Miscellaneous Plan fiduciary net position as a percentage of the total pension liability	75.53%	72.96%	72.65%	84.40%	72.64%
Measurement date:	June 30, 2024	June 30, 2023	June 30, 2022	June 30, 2021	June 30, 2020

Measurement Date	2020	2019	2018	2017	2016
AMP's proportion of the City's Net pension liability	31.99%	30.26%	30.19%	29.84%	29.00%
AMP's proportionate share of the City's net pension liability	$26,437,127	$24,012,403	$24,557,226	$21,006,196	$16,040,814
AMP's Covered payroll	$8,610,858	$8,319,740	$8,023,529	$8,023,529	$7,471,151
AMP's proportionate share of the City's net pension liability as a percentage of covered payroll	307.02%	288.62%	306.07%	261.81%	214.70%
Miscellaneous Plan fiduciary net position as a percentage of the total pension liability	72.80%	72.90%	71.50%	72.92%	77.96%
Measurement date:	June 30, 2019	June 30, 2018	June 30, 2017	June 30, 2016	June 30, 2015

Alameda Municipal Power
Schedule of AMP's Pension Contributions
Last 10 Fiscal Years

Fiscal Year End	2025	2024	2023	2022	2021
Actuarially determined contributions	$3,372,606	$3,143,794	$3,065,003	$2,796,392	$2,981,913
Contributions in relation to the actuarially determined contribution	3,372,606	3,143,794	3,065,003	2,796,392	2,981,913
Contribution deficiency (excess)	$ -	$ -	$ -	$ -	$ -
Covered payroll	$9,999,629	$9,540,161	$8,428,246	$8,062,367	$9,412,682
Contributions as a percentage of covered payroll	33.73%	32.95%	36.37%	34.68%	31.68%

Fiscal Year End	2020	2019	2018	2017	2016
Actuarially determined contributions	$2,504,271	$2,105,125	$1,739,297	$1,631,001	$1,312,978
Contributions in relation to the actuarially determined contribution	2,504,271	2,105,125	1,739,297	1,631,001	1,312,978
Contribution deficiency (excess)	$ -	$ -	$ -	$ -	$ -
Covered payroll	$9,317,305	$8,610,858	$8,442,308	$8,319,740	$8,023,529
Contributions as a percentage of covered payroll	26.88%	24.45%	20.60%	19.60%	16.36%

Alameda Municipal Power

Schedule of AMP’s Proportionate Share of the City’s OPEB Liability and Related Ratios

Last 10 Fiscal Years*

	2025	2024	2023	2022	2021
AMP's proportion of the City's net OPEB Liability	2.22%	2.22%	2.22%	2.22%	2.22%
AMP's proportion share of the City's net OPEB Liability	$958,114	$1,002,488	$977,460	$1,343,869	$1,754,728
AMP's covered-employee payroll	$10,209,072	$9,521,728	$9,225,705	$9,753,126	$10,219,761
AMP's Proportionate share of the City's net OPEB Liability as a percentage of covered empoyee payroll	9.38%	10.53%	10.59%	13.78%	17.17%
Measurement date:	June 30, 2025	June 30, 2024	June 30, 2023	June 30, 2022	June 30, 2021

	2020	2019	2018*
AMP's proportion of the City's net OPEB Liability	2.22%	2.22%	1.92%
AMP's proportion share of the City's net OPEB Liability	$1,584,849	$1,495,574	$1,495,574
AMP's covered-employee payroll	$10,122,337	$9,583,967	$9,250,613
AMP's Proportionate share of the City's net OPEB Liability as a percentage of covered empoyee payroll	15.66%	15.60%	16.17%
Measurement date:	June 30, 2020	June 30, 2019	June 30, 2018

* Fiscal year 2018 was the first year of implementation of GASB 75

Alameda Municipal Power
Schedule of AMP's OPEB Contributions
Last 10 Fiscal Years*

Fiscal Year	2025	2024	2023	2022	2021
AMP's proportion of the City's net OPEB Liability	$958,114	$1,002,488	$977,460	$1,343,869	$1,754,728
Actuarially determined Contributions**	71,647	77,410	77,410	77,410	77,410
AMP's proportion share of the City's net OPEB Liability	71,647	77,410	77,410	77,410	77,410
Contribution deficiency (excess)	$ -	$ -	$ -	$ -	$ -
AMP's covered-employee payroll	$10,209,072	$9,521,728	$9,225,705	$9,753,126	$10,219,761
AMP's Proportionate share of the City's net OPEB Liability as a percentage of covered empoyee payroll	0.093849274	11%	0%	10%	17%
Contributions as a percentage of covered employee payroll	0.007017974	0.81%	0.84%	0.79%	0.76%

Fiscal Year	2020	2019	2018*
AMP's proportion of the City's net OPEB Liability	$1,584,849	$1,495,574	$1,979,781
Actuarially determined Contributions**	77,410	77,410	
AMP's proportion share of the City's net OPEB Liability	77,410	77,410	
Contribution deficiency (excess)	$ -	$ -	$ -
AMP's covered-employee payroll	$10,122,337	$9,583,967	$9,250,613
AMP's Proportionate share of the City's net OPEB Liability as a percentage of covered empoyee payroll	16%	16%	21%
Contributions as a percentage of covered employee payroll	0.76%	0.81%	0.00%

* Fiscal year 2018 was the first year of implementation of GASB 75
** The City established an irrevocable trust in fiscal year 2019

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Statistical Section

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STATISTICAL SECTION

This part of the Alameda Municipal Power's (AMP) Annual Comprehensive Financial Report presents detailed information as a context for understanding what the information in the financial statements, note disclosures, and required supplementary information says about AMP's overall financial health. In contrast to the financial section, the statistical section information is not subject to independent audit.

Financial Trends
These schedules contain trend information to help the reader understand how AMP's financial performance and well being have changed over time:

1. Net Position by Component
2. Changes in Net Position of Consolidated Operations
3. Changes in Net Position of Electric Operations and Telecommunication Operations

Revenue Capacity
These schedules contain information to help the reader assess AMP's revenue sources:

1. Electric Operating Revenues by Source
2. Customer Accounts
3. Pricing Changes

Debt Capacity
These schedules present information to help the reader assess the affordability of AMP's current levels of outstanding debt and AMP's ability to issue additional debt in the future:

1. Outstanding Debt by Type
2. Revenue Bonds/Certificates of Participation Coverage – Electric Operations
3. Certificates of Participation Coverage – Telecommunication Operations

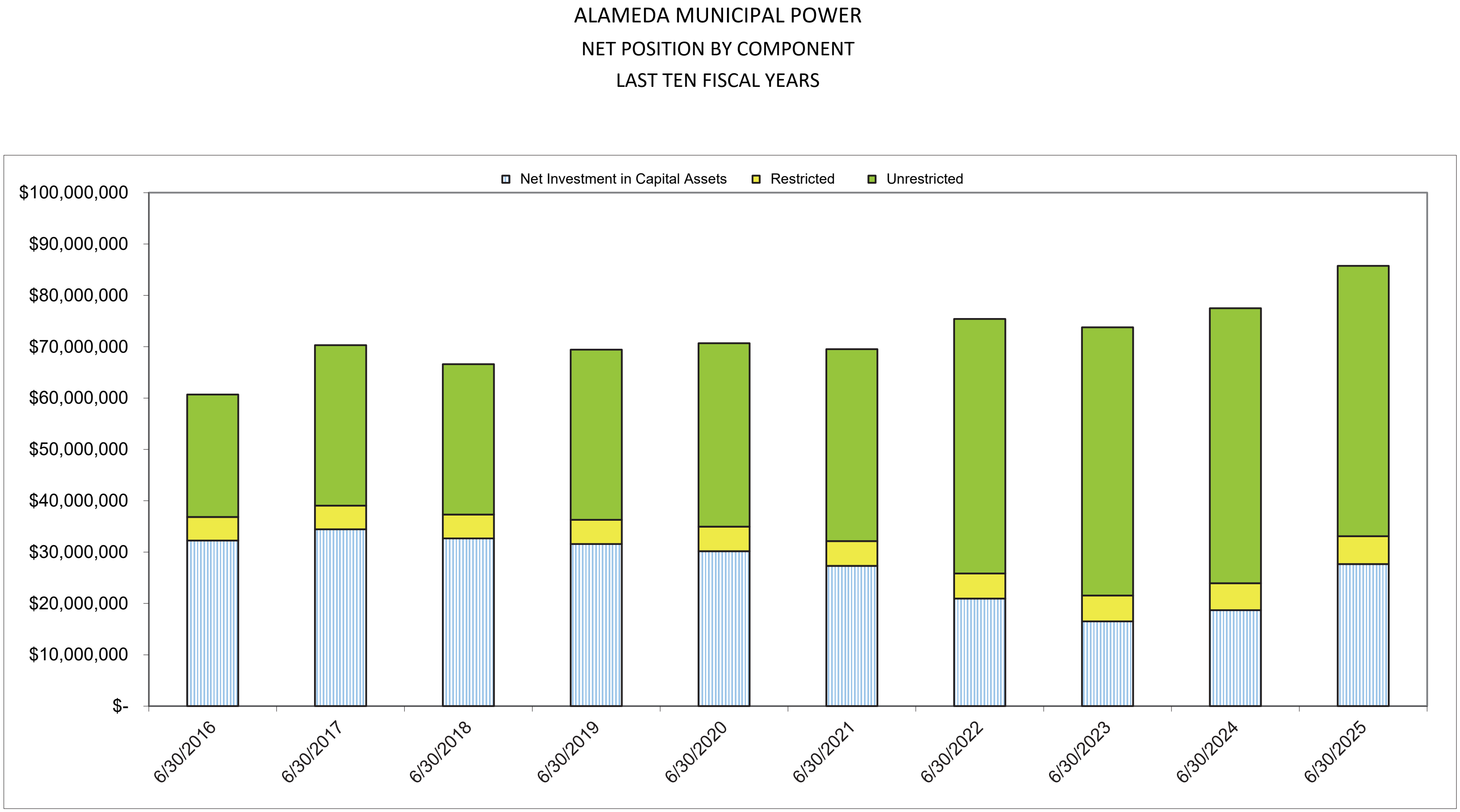
Demographic and Economic Information
These schedules offer demographic and economic indicators to help the reader understand the environment within which AMP's financial activities take place:

1. Demographic and Economic Statistics
2. Top 10 Customers and City's Principal Employers

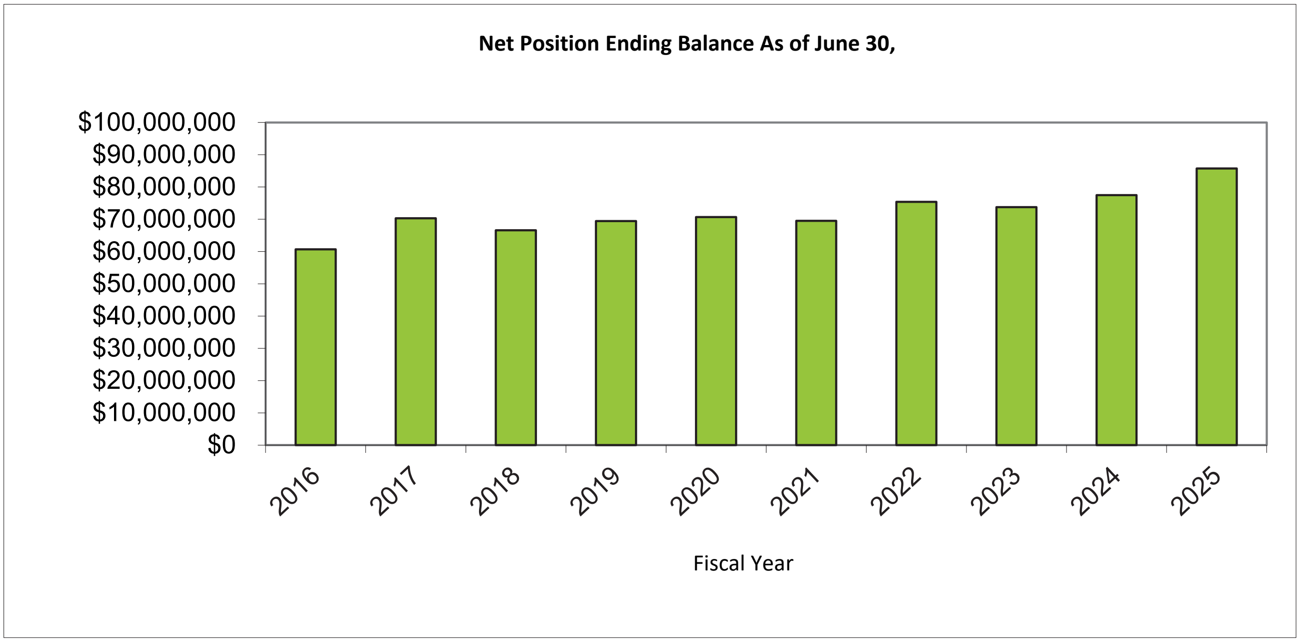
Operating Information
These schedules contain service and infrastructure data to help the reader understand how the information in AMP's financial report relates to the services that AMP provides and the activities it performs:

1. Operating Expenses by Function per FERC Codes – Electric Operations
2. Operating Expenses by Function per FERC Codes –Telecommunications Operations
3. Capital Asset Statistics by Function/Program
4. Operation Indicators
5. Days Cash on Hand

Sources
Unless otherwise noted, the information in these schedules is derived from the Annual Comprehensive Financial Reports for the relevant year.



	Fiscal Year Ended,									
	6/30/2016	6/30/2017	6/30/2018	6/30/2019	6/30/2020	6/30/2021	6/30/2022	6/30/2023	6/30/2024	6/30/2025
Net Position:										
Net Investment in Capital Assets	$ 32,252,428	$ 34,437,310	$ 32,661,774	$ 31,576,345	$ 30,184,887	$ 27,332,261	$ 20,968,253	$ 16,507,878	$ 18,677,596	$ 27,673,212
Restricted	4,581,311	4,608,923	4,661,503	4,719,758	4,777,285	4,806,648	4,882,008	5,046,307	5,258,532	5,440,578
Unrestricted	23,848,220	31,259,576	29,278,601	33,134,340	35,731,238	37,380,508	49,557,794	52,217,409	53,554,547	52,643,790
Total Net Position	$ 60,681,959	$ 70,305,809	$ 66,601,878	$ 69,430,443	$ 70,693,410	$ 69,519,417	$ 75,408,055	$ 73,771,594	$ 77,490,675	$ 85,757,580



Fiscal Year	Operating Revenues	Operating Expenses	Operating Income	Non-Operating Revenue, Expenses & Transfers	Change in Net Position	Net Position Beginning Balance	Net Position Ending Balance
2016	62,012,528	51,230,776	10,781,752	(4,193,192)	6,588,560	54,093,399	60,681,959
2017	63,449,233	50,432,498	13,016,735	(3,392,887)	9,623,848	60,681,959	70,305,807
2018	64,602,195	54,463,482	10,138,713	(11,840,882)	(1,702,169)	68,304,047	66,601,878
2019	67,078,362	59,472,881	7,605,481	(4,776,916)	2,828,565	66,601,878	69,430,443
2020	67,066,350	60,324,301	6,742,049	(5,479,082)	1,262,967	69,430,443	70,693,410
2021	66,545,894	61,467,744	5,078,150	(6,252,143)	(1,173,993)	70,693,410	69,519,417
2022	66,299,177	54,345,047	11,954,130	(6,065,492)	5,888,638	69,519,417	75,408,055
2023	72,970,573	67,346,932	5,623,641	(7,260,102)	(1,636,461)	75,408,055	73,771,594
2024	78,126,818	72,133,506	5,993,312	(2,274,231)	3,719,081	73,771,594	77,490,675
2025	81,920,888	73,122,260	8,798,628	(531,723)	8,266,905	77,490,675	85,757,580

Changes in Net Position of Electric Operations

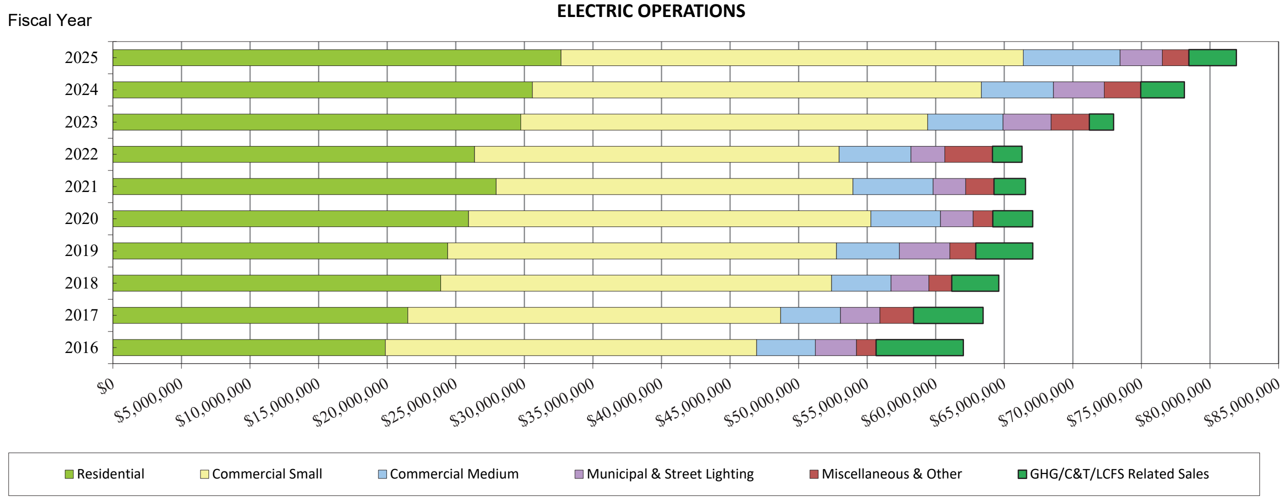
Fiscal Year	Operating Revenues	Operating Expenses	Operating Income	Non-Operating Revenue, Expenses & Transfers	Change in Net Position	Net Position Beginning Balance	Net Position Ending Balance
2016	62,012,528	51,230,776	10,781,752	(4,193,192)	6,588,560	54,093,399	60,681,959
2017	63,449,233	50,432,498	13,016,735	(3,392,887)	9,623,848	60,681,959	70,305,807
2018**	64,602,195	54,463,482	10,138,713	(11,840,882)	(1,702,169)	68,304,047	66,601,878
2019	67,078,362	59,472,881	7,605,481	(4,776,916)	2,828,565	66,601,878	69,430,443
2020	67,066,350	60,324,301	6,742,049	(5,479,082)	1,262,967	69,430,443	70,693,410
2021	66,545,894	61,467,744	5,078,150	(6,252,143)	(1,173,993)	70,693,410	69,519,417
2022	66,299,177	54,345,047	11,954,130	(6,065,492)	5,888,638	69,519,417	75,408,055
2023	72,970,573	67,346,932	5,623,641	(7,260,102)	(1,636,461)	75,408,055	73,771,594
2024	78,126,818	72,133,506	5,993,312	(2,274,231)	3,719,081	73,771,594	77,490,675
2025	81,920,888	73,122,260	8,798,628	(531,723)	8,266,905	77,490,675	85,757,580

** 2018 Net Position Beginning Balance is restated adopting GASB No. 68 "Accounting and Financial Reporting for Pensions (OPEB)"

Changes in Net Position of Telecommunications Operations

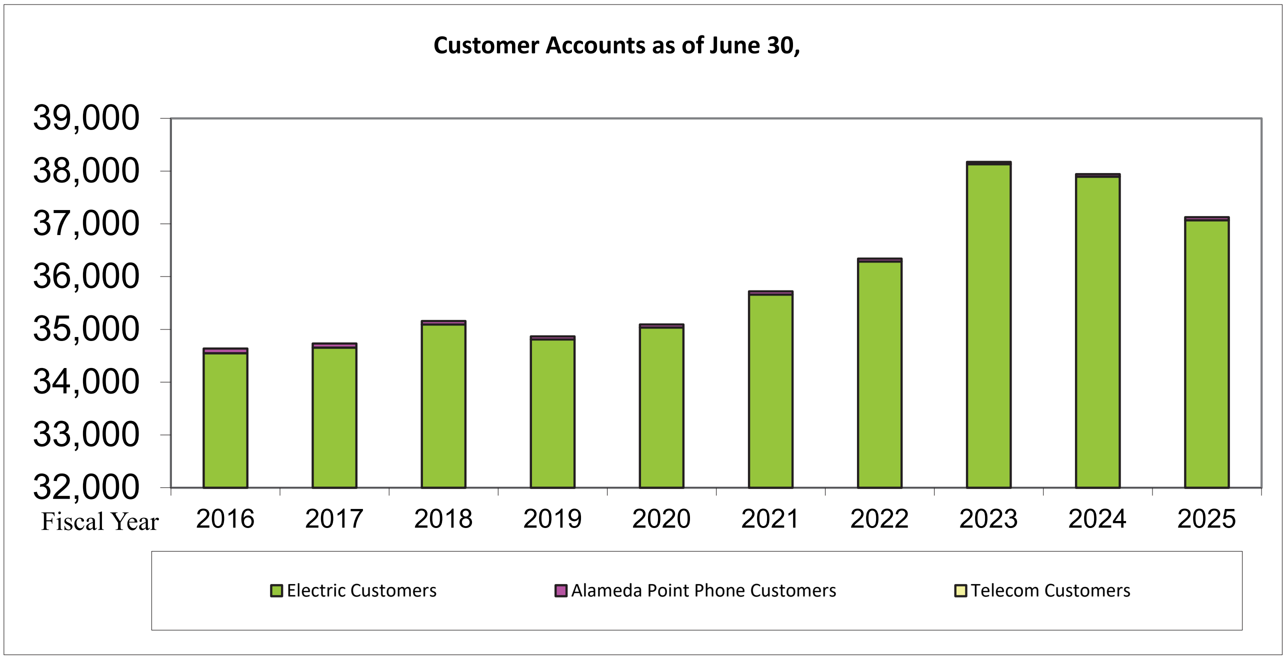
Fiscal Year	Operating Revenues	Operating Expenses	Operating Income	Non-Operating Revenue, Expenses, Transfers and Special Items	Change in Net Position	Net Position Beginning Balance	Net Position Ending Balance
2016	-	-	-	2,200,000	2,200,000	(2,200,000)	-
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-

ELECTRIC OPERATIONS



	Sales of Electricity								
Fiscal Year	Residential	Commercial Small	Commercial Medium	Municipal	Street Lighting/ Other	Miscellaneous Services	Plant Lease & Jobbing Sales	GHG/C&T/LCFS Related Sales	Total
2016	$ 19,869,104	$ 27,071,358	$ 4,278,240	$ 1,973,689	$ 1,028,631	$ 947,765	$ 479,791	$ 6,363,950	$ 62,012,528
2017	21,510,126	27,177,335	4,366,885	1,958,154	913,248	1,275,191	1,177,119	5,071,175	63,449,233
2018	23,902,788	28,500,186	4,338,898	1,965,664	793,870	1,146,507	519,200	3,435,082	64,602,195
2019	24,414,010	28,354,299	4,580,711	2,225,142	1,453,471	510,524	1,380,846	4,159,358	67,078,362
2020	25,933,443	29,341,107	5,069,275	2,238,296	149,514	362,644	1,062,614	2,909,457	67,066,350
2021	27,946,417	26,015,342	5,845,303	2,058,753	320,052	284,931	1,778,194	2,296,903	66,545,894
2022	26,375,111	26,584,210	5,230,140	2,455,536	15,350	499,947	2,973,677	2,165,206	66,299,177
2023	29,742,058	29,670,943	5,493,443	2,536,925	970,954	682,855	2,108,141	1,765,255	72,970,573
2024	30,590,103	32,733,484	5,256,043	2,722,668	981,614	656,643	2,006,598	3,179,665	78,126,818
2025	32,679,325	33,702,969	7,060,102	2,791,253	292,019	593,039	1,343,601	3,458,580	81,920,888

	Kilowatt- Hour Sales					
Fiscal Year	Residential	Commercial Small	Commercial Medium	Municipal	Street Lighting/ Other	Total KWH	Peak Demand (KW)
2016	125,831,929	176,575,883	31,490,040	12,375,517	2,546,494	348,819,863	64,283
2017	126,850,402	172,520,353	30,127,960	11,428,198	2,838,825	343,765,738	63,738
2018	124,589,523	168,873,305	28,321,180	10,723,565	2,518,330	335,025,903	59,624
2019	125,510,907	164,807,447	28,712,440	11,064,274	2,034,011	332,129,079	54,362
2020	129,591,566	166,745,235	31,301,090	11,539,236	2,605,615	341,782,742	61,990
2021	138,607,950	146,664,721	35,641,270	10,470,953	2,548,136	333,933,030	62,664
2022	130,100,333	150,731,047	31,576,810	12,536,267	1,763,268	326,707,725	60,551
2023	142,845,315	160,854,387	31,982,570	12,541,574	2,307,674	350,531,520	64,002
2024	135,285,528	167,903,386	28,368,710	12,555,799	1,912,228	346,025,651	60,014
2025	139,424,569	168,243,579	37,107,650	12,566,651	1,705,736	359,048,185	67,239



Number of Electric Customer Accounts:

Fiscal Year	Residential	Commercial Small	Commercial Medium	Commercial Large	Municipal	Street Lighting & Other	Total Customer Accounts
2016	30,470	3,425	280	8	354	11	34,548
2017	30,495	3,437	327	12	365	18	34,654
2018	30,798	3,577	321	12	373	13	35,094
2019	30,650	3,479	303	7	356	14	34,809
2020	30,872	3,481	294	10	361	18	35,036
2021	31,349	3,627	283	9	378	15	35,661
2022	32,058	3,542	312	11	348	14	36,285
2023	33,850	3,608	286	9	363	14	38,130
2024	33,711	3,531	279	15	350	9	37,895
2025	32,877	3,526	287	20	351	9	37,070

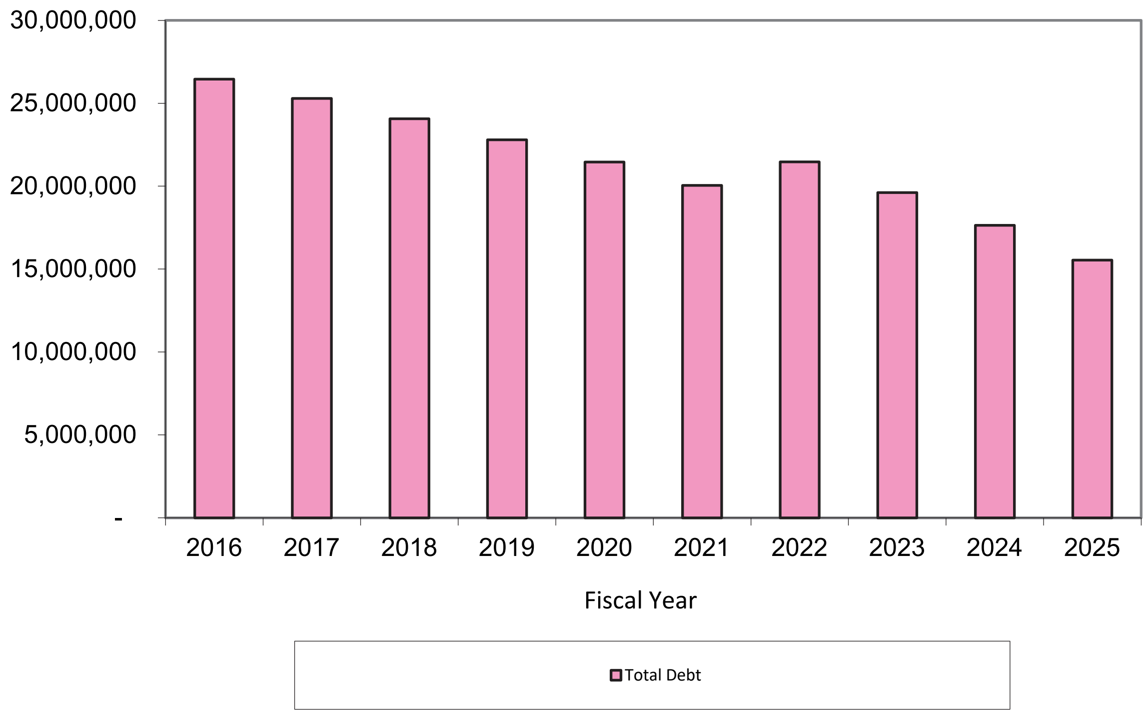
NOTE: Telecommunication operation was sold in November 2008 - 10 year historical data is zero for 2009 onwards

Fiscal Year	Cable TV	Internet Data	Telecommunications* Customer Accounts	Alameda Point Telephone Customer Accounts
2016	-	-	-	88
2017	-	-	-	79
2018	-	-	-	66
2019	-	-	-	59
2020	-	-	-	58
2021	-	-	-	61
2022	-	-	-	57
2023	-	-	-	44
2024	-	-	-	48
2025	-	-	-	56

*Telecommunication operation was sold in November 2008

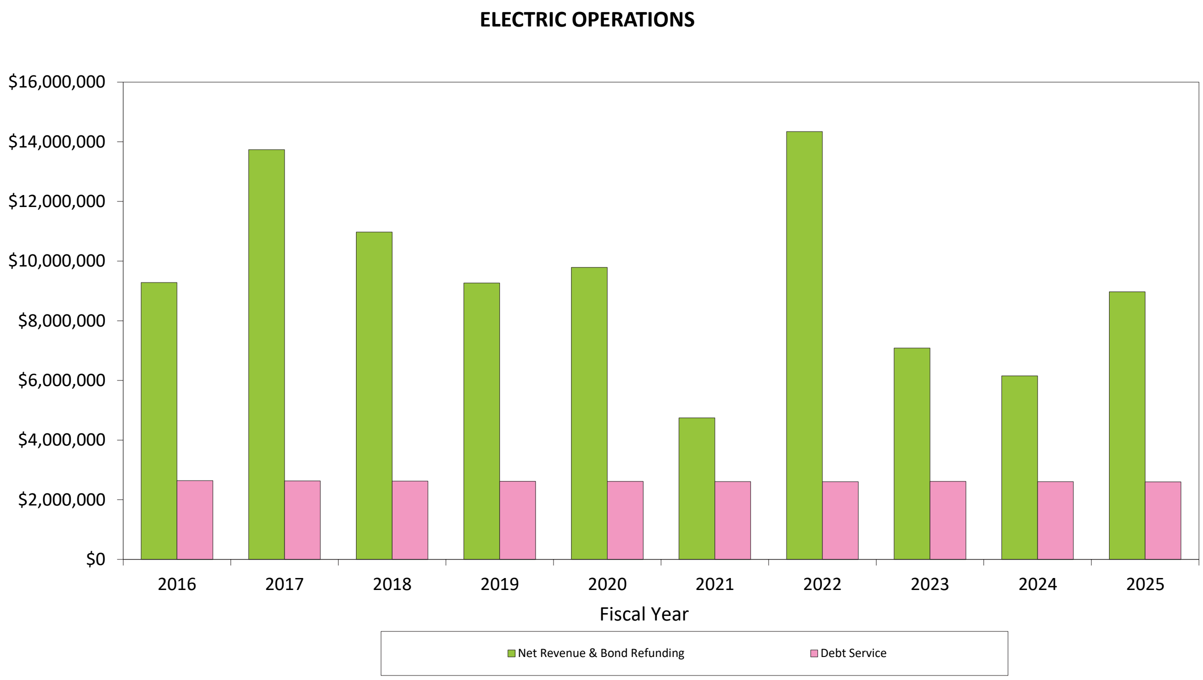
Electric Rate Changes

Date	Percent Change	
July 1, 2016	5.00%	
July 1, 2017	5.00%	
July 1, 2018	1.00%	
July 1, 2019	2.50%	
July 1, 2020	0.00%	
July 1, 2021	0.00%	
July 1, 2022	5.00%	
July 1, 2023	7.00%	
July 1, 2024	3.00%	
July 1, 2025	4.00%	(Fiscal Year 2026)

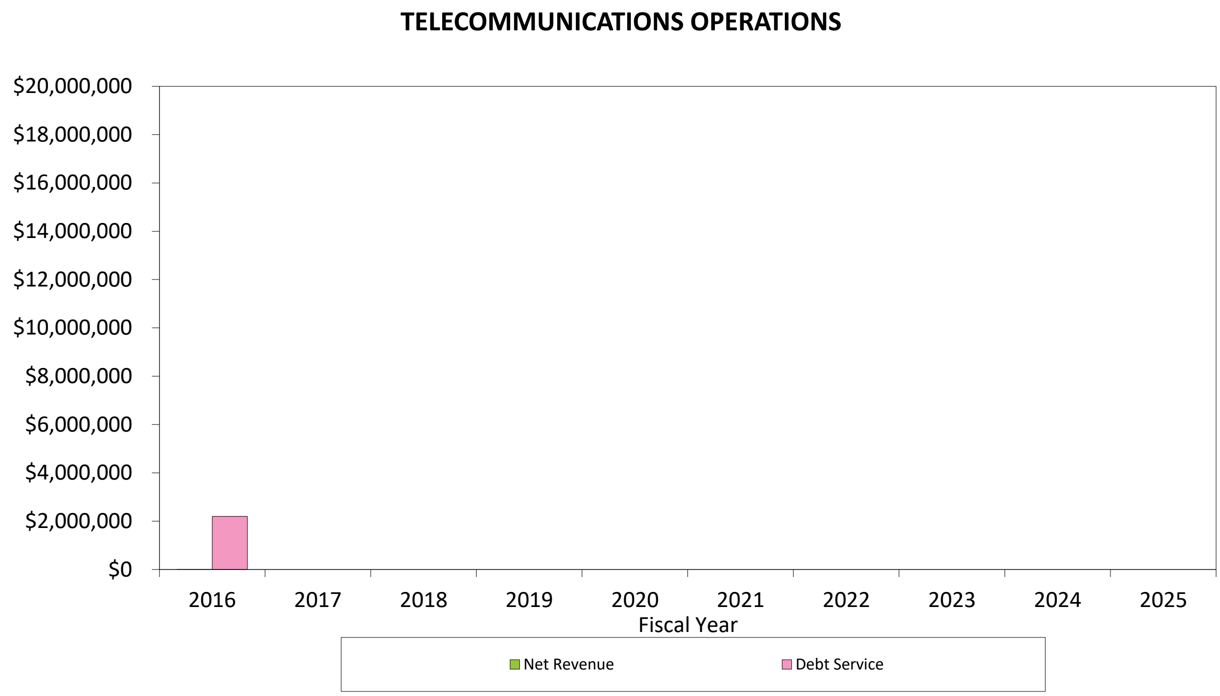


Fiscal Year	Certificates of Participation	Revenue Bonds/ Anticipation Notes	Loans and Lease Purchases	Total	Per Customer Accounts	Per Capita (a)
2016	-	26,460,000	-	26,460,000	767.09	333.77
2017	-	25,290,000	-	25,290,000	726.93	316.41
2018	-	24,070,000	-	24,070,000	680.02	301.15
2019	-	22,795,000	-	22,795,000	644.00	287.39
2020	-	21,455,000	-	21,455,000	594.87	263.86
2021	-	20,045,000	-	20,045,000	562.10	257.70
2022	-	18,560,000	2,908,512	21,468,512	511.51	240.14
2023	-	16,960,000	2,657,081	19,617,081	447.55	219.44
2024	-	15,255,000	2,387,806	17,642,806	465.57	225.98
2025	-	13,440,000	2,099,837	15,539,837	419.20	196.66

Source: (a) City of Alameda (population)

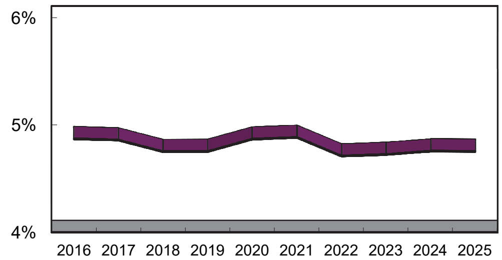


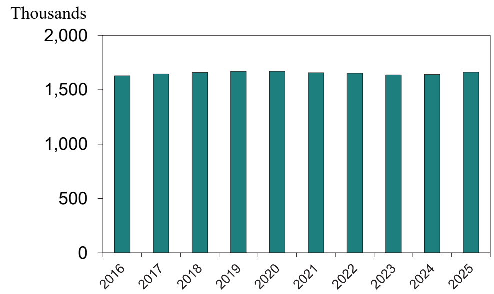
Fiscal Year	Electric Gross Revenue Including Non-Operating Revenue	GHG/C&T Related Sales Net Revenue Not Available for Debt Service	Electric Direct Operating Expenses (Excluding Depreciation)	Net Revenue Available for Debt Service, Renewals, Replacements and Additions	Debt Service Principal	Debt Service Interest and Fiscal Charges	Debt Service Total	Coverage
2016	63,509,684	6,363,950	47,864,750	9,280,984	1,130,000	1,510,325	2,640,325	3.52
2017	65,735,599	5,071,175	46,926,046	13,738,378	1,170,000	1,461,044	2,631,044	5.22
2018	65,532,532	3,435,082	51,123,219	10,974,231	1,220,000	1,406,364	2,626,364	4.18
2019	69,044,773	4,159,358	55,616,579	9,268,836	1,275,000	1,342,703	2,617,703	3.54
2020	69,124,622	2,909,457	56,426,290	9,788,875	1,340,000	1,273,787	2,613,787	3.75
2021	64,305,751	2,296,903	57,265,781	4,743,067	1,410,000	1,199,156	2,609,156	1.82
2022	66,299,177	2,165,206	49,791,154	14,342,817	1,485,000	1,118,327	2,603,327	5.51
2023	72,970,573	1,765,255	64,122,157	7,083,161	1,600,000	1,014,055	2,614,055	2.71
2024	78,126,818	3,179,665	68,797,667	6,149,486	1,705,000	902,940	2,607,940	2.36
2025	81,920,888	3,458,580	69,490,564	8,971,744	1,815,000	784,656	2,599,656	3.45

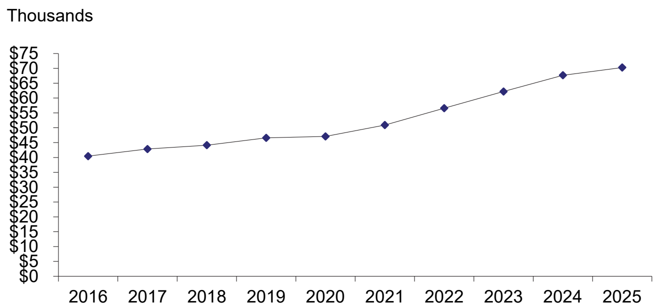


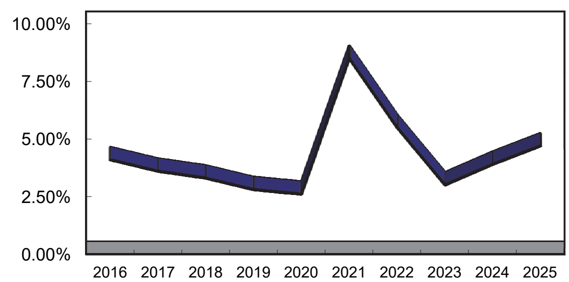
Fiscal Year	Gross Revenue Including Non-Operating Revenue	Direct Operating Expenses (Excluding Depreciation)	Net Revenue Available for Debt Service, Renewals, Replacements and Additions	Debt Service: Principal	Debt Service: Interest and Fiscal Charges	Debt Service: Total	Coverage
2016	9,977	-	9,977	2,200,000	-	2,200,000	0.00
2017	-	-	-	-	-	-	Not Applicable
2018	-	-	-	-	-	-	Not Applicable
2019	-	-	-	-	-	-	Not Applicable
2020	-	-	-	-	-	-	Not Applicable
2021	-	-	-	-	-	-	Not Applicable
2022	-	-	-	-	-	-	Not Applicable
2023	-	-	-	-	-	-	Not Applicable
2024	-	-	-	-	-	-	Not Applicable
2025	-	-	-	-	-	-	Not Applicable

*Telecommunication operations was sold in November 2008. Sale proceed was used to pay debt principal.









Fiscal Year	City Population	Total Personal Income	Per Capita Personal Income	Unemployment Rate (%)	Alameda County Population	City Population % of County
2016	79,277	3,207,096,000	40,454	4.1%	1,627,865	4.87%
2017	79,928	3,423,524,000	42,832	3.6%	1,645,359	4.86%
2018	78,863	3,529,109,000	44,153	3.3%	1,660,202	4.75%
2019	79,316	3,695,508,000	46,592	2.8%	1,669,301	4.75%
2020	81,312	3,828,228,000	47,080	2.6%	1,670,834	4.87%
2021	80,884	4,118,360,000	50,916	8.5%	1,656,591	4.88%
2022	77,784	4,401,297,000	56,583	5.5%	1,651,979	4.71%
2023	77,287	4,807,291,000	62,200	3.0%	1,636,194	4.72%
2024	78,071	5,283,851,000	67,680	3.9%	1,641,869	4.76%
2025	79,020	5,553,945,000	70,285	4.7%	1,662,482	4.75%

Source: California State Department of Finance

Top 10 Customers

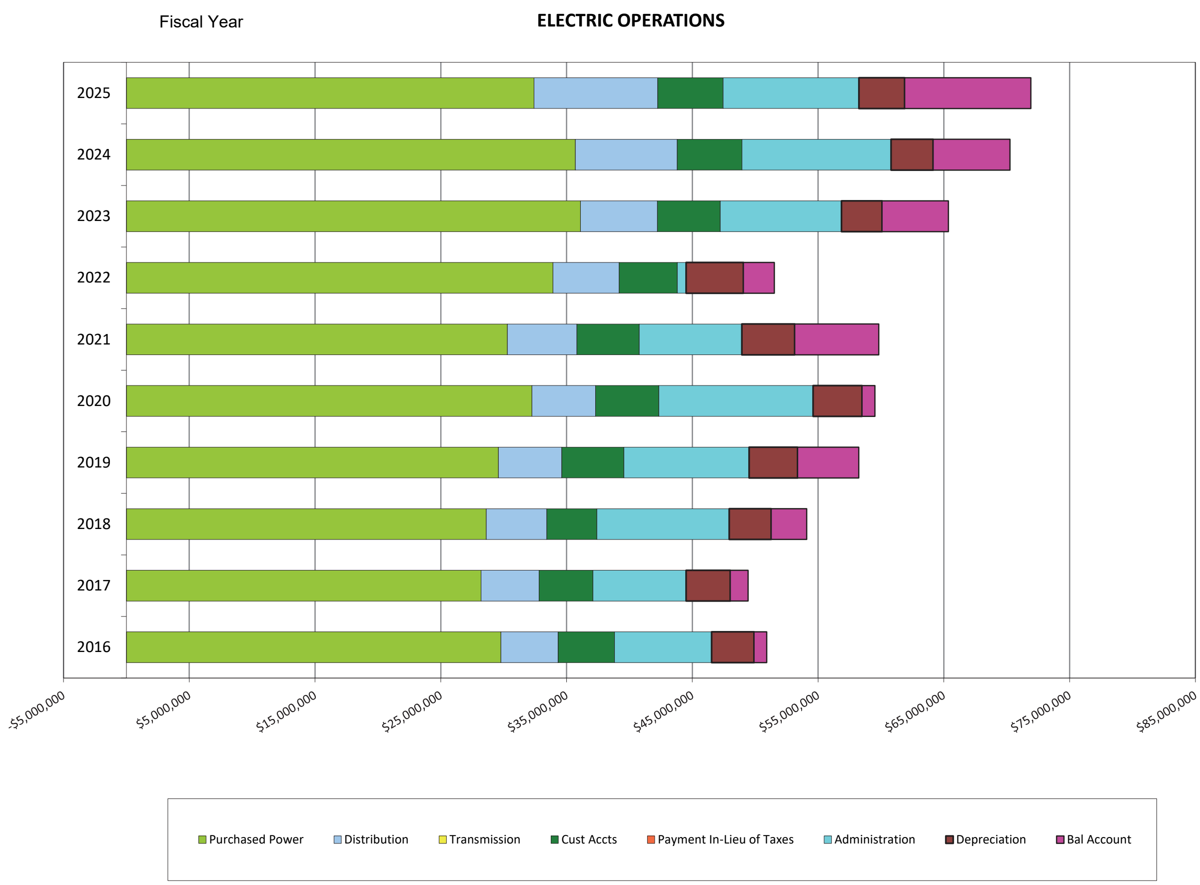
No.	Customer	Type of Business	KWHS	Percent of System Total	Revenues	Percent of System Total
1	U.S. Coast Guard	Regulation, Admin. of Transportation	18,801,447	5.24%	$ 3,415,181	4.46%
2	Penumbra, Inc.	Medical Devices Developer/Manufacturer	9,920,172	2.76%	1,917,388	2.51%
3	G&I IX Marina Research Park LP	Life Science & Research Tenants	8,761,701	2.44%	1,817,752	2.38%
4	Exelixis	Biopharmaceutical Company	6,737,955	1.88%	1,386,605	1.81%
5	City of Alameda	Local Government	6,147,810	1.71%	1,402,793	1.83%
6	Alameda Unified School District	Public School District	5,958,022	1.66%	1,256,822	1.64%
7	Sila Nanotechnologies	An Engineered Materials Company	5,268,408	1.47%	1,022,529	1.34%
8	Abbott Diabetes Care	Healthcare Industry	4,992,926	1.39%	876,511	1.15%
9	Peets Coffee & Tea	Coffee Roaster and Retailer	4,761,440	1.33%	922,398	1.21%
10	San Leandro Health System	Hospital, Medical and Emergency Services	4,478,097	1.25%	861,205	1.13%
	Top 10 Customers KWHS		75,827,978	21.12%	14,879,184	19.44%
	Total Kilowatt Hour Sales		359,048,185	100%	76,525,668	100%

Principal Employers

	2024-25			2015-16		
Employer	Number of Employees	Rank	Percentage of Total City Employment	Number of Employees	Rank	Percentage of Total City Employment
Penumbra, Inc.	1848	1	2.34 %	858	2	1.08 %
Alameda Unified School District	1695	2	2.15 %	876	1	1.10 %
Exelixis	749	3	0.95 %			
Alameda Alliance for Health	670	4	0.85 %	694	4	0.88 %
City Of Alameda	584	5	0.74 %	518	6	0.65 %
Sila Nanotechnologies	407	6	0.52 %			
World Market Management Services	383	7	0.48 %			
Safeway Stores	365	8	0.46 %	480	8	0.61 %
Bay Ship & Yacht Company	340	9	0.43 %			
Webcor Craft	295	10	0.37 %			
VF Outdoor				751	3	0.95 %
Oakland Raiders				604	5	0.76 %
Abbott Diabetes Care				512	7	0.65 %
Wind River Systems				447	9	0.56 %
Kaiser Foundation Health Plan				425	10	0.54 %
Subtotal	7336		9.28 %	6165		7.78 %
Total City Day Population	79020			79277		

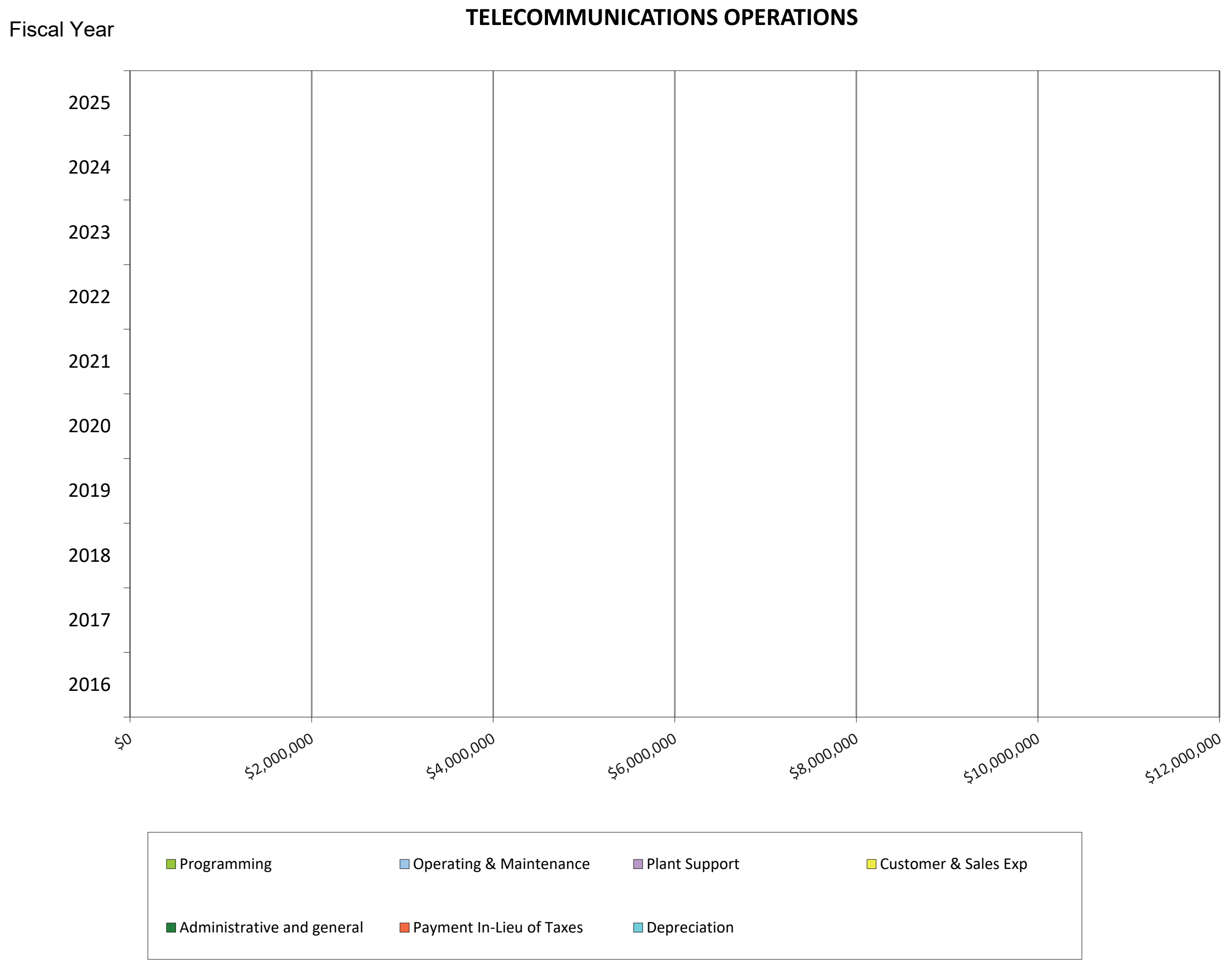
Source: City of Alameda

Alameda Municipal Power
Operating Expenses by Function per FERC Codes
Last Ten Fiscal Years



Fiscal Year	Purchased Power	Distribution Operation	Transmission-Maintenance	Customer Accounts	Administration	*Payment In-lieu of Taxes	Depreciation	Jobbing Sales Expenses	Balancing Account	Total
2016	29,781,270	4,549,165	2,414	4,483,281	7,723,065	-	3,366,025	315,472	1,010,084	51,230,776
2017	28,201,607	4,618,340	-	4,274,066	7,412,807	-	3,506,452	993,589	1,425,636	50,432,497
2018	28,618,484	4,814,122	-	3,974,327	10,527,575	-	3,340,263	367,624	2,821,087	54,463,482
2019	29,586,832	5,033,334	-	4,939,441	9,954,555	-	3,856,302	1,242,159	4,860,258	59,472,881
2020	32,246,283	5,055,482	-	5,038,324	12,261,784	-	3,898,011	803,802	1,020,615	60,324,301
2021	30,296,114	5,524,880	-	4,959,115	8,158,825	-	4,201,963	1,646,595	6,680,252	61,467,744
2022	33,920,081	5,260,275	-	4,625,203	698,303	-	4,553,893	2,822,759	2,464,533	54,345,047
2023	36,101,823	6,124,728	-	4,990,365	9,641,760	-	3,224,775	1,985,502	5,277,979	67,346,932
2024	35,696,806	8,104,162	-	5,151,625	11,854,975	-	3,335,839	1,874,528	6,115,571	72,133,506
2025	32,416,136	9,831,397	-	5,204,894	10,797,776	-	3,631,696	1,202,689	10,037,672	73,122,260

*Payment-in-lieu of taxes is included in non-operating revenues (expenses) to conform with 2010 A/B Bond operating expense definitions.



Fiscal Year	Programming & Access	Operating & Maintenance	Plant Support	Customer A/C & Sale Expenses	Administration	Payment In-lieu of Taxes	Depreciation	Total
2016	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-

*Telecommunication operation was sold in November 2008

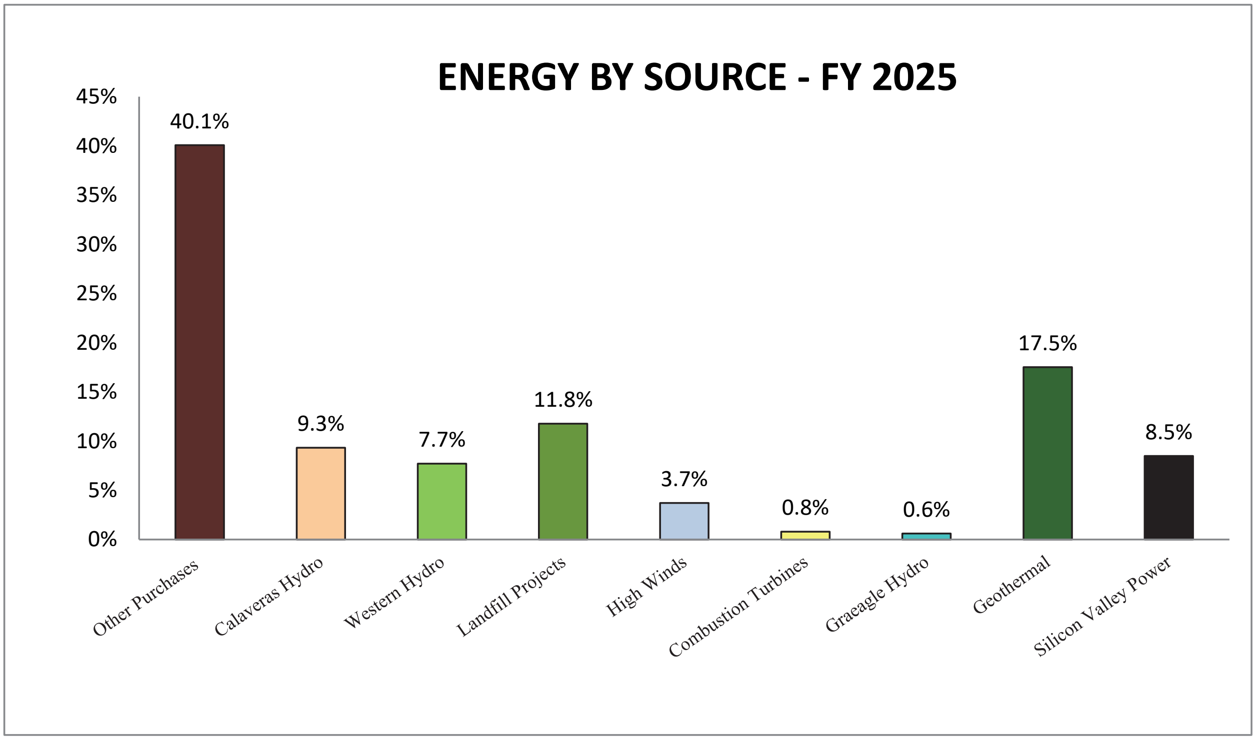
Alameda Municipal Power

Capital Asset Statistics by Function / Program

Last Ten Fiscal Years

ELECTRIC OPERATIONS

Fiscal Year	Plant	Service Center Building	Land, Rights & Easements	Machinery & Equipment	Transportation Equipment	Computer Equipment	Furniture & Fixtures	Right to Use Capital Asset	Construction in Progress	Less: Accumulated Depreciation	Net Electric Capital Assets
2016	84,548,411	7,850,886	339,143	9,439,316	3,048,241	3,832,459	835,790		1,736,459	(71,425,024)	40,205,681
2017	84,654,592	8,071,667	339,143	9,510,378	3,240,418	4,158,116	835,790		6,452,324	(74,534,854)	42,727,575
2018	86,123,810	8,130,625	339,143	9,620,376	3,318,156	4,168,912	899,922		2,872,673	(74,267,672)	41,205,945
2019	86,915,116	8,168,069	220,143	9,725,953	3,402,639	4,377,329	899,922		3,862,220	(77,856,842)	39,714,550
2020	87,421,782	8,168,069	220,143	9,725,953	3,405,737	4,683,748	923,119		5,198,491	(81,362,299)	38,384,743
2021	90,553,163	8,168,069	220,143	9,951,651	3,846,642	4,694,928	980,488		3,007,674	(85,453,930)	35,968,827
2022	90,860,802	8,168,069	220,143	9,928,243	4,007,652	4,302,479	977,905	3,142,914	3,728,600	(89,556,558)	35,780,248
2023	91,245,305	8,168,069	220,144	9,928,243	4,290,177	4,302,479	977,905	3,142,914	6,315,865	(92,781,333)	35,809,766
2024	92,493,588	8,168,069	220,144	10,094,645	4,527,519	4,859,566	977,905	3,142,914	7,699,683	(96,117,172)	36,066,859
2025	94,863,770	8,168,069	220,144	10,094,645	4,220,390	5,112,799	977,905	3,142,914	13,913,211	(97,692,690)	43,021,157



Energy By Source
Last Ten Fiscal Years

Fiscal Year	Other Purchases	Calaveras Hydro	Western Hydro	Landfill Projects	High Winds	Combustion Turbines	Graeagle Hydro	Geothermal	Silicon Valley Power	Total
2016	63.57%	10.91%	7.05%	12.07%	5.44%	0.40%	0.55%	0.00%	0.00%	100.00%
2017	38.52%	25.67%	16.00%	12.29%	5.71%	1.03%	0.77%	0.00%	0.00%	100.00%
2018	52.13%	13.98%	10.41%	11.68%	5.54%	1.42%	0.80%	4.03%	0.00%	100.00%
2019	37.00%	24.22%	11.97%	8.52%	5.88%	1.50%	0.58%	10.32%	0.00%	100.00%
2020	26.92%	12.79%	11.30%	14.91%	5.28%	0.90%	0.70%	16.90%	10.30%	100.00%
2021	5.11%	6.14%	7.60%	23.51%	6.35%	3.21%	0.46%	37.13%	10.50%	100.00%
2022	5.48%	7.91%	4.88%	22.36%	5.63%	2.23%	0.65%	40.17%	10.71%	100.00%
2023	0.00%	24.77%	5.98%	22.87%	5.14%	0.78%	0.59%	29.70%	10.16%	100.00%
2024	7.52%	17.31%	11.58%	22.73%	3.69%	0.62%	0.78%	25.57%	10.21%	100.00%
2025	40.08%	9.33%	7.71%	11.77%	3.72%	0.79%	0.60%	17.52%	8.49%	100.00%

Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Since:	1887	1887	1887	1887	1887	1887	1887	1887	1887	1887
Budgeted Employees	98	98	97	94	92	92	94	91	91	91
Vehicles in Service	46	46	46	45	42	42	43	49	49	39
Service Area (Miles)	22.80	22.80	22.80	22.80	22.80	22.80	22.80	22.80	22.80	22.80
Transmission Lines (115kV)										
Overhead Pole Miles	6.77	6.77	6.77	6.77	6.77	6.77	6.77	6.77	6.77	6.77
Underground Circuit Miles	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93
Distribution Lines (12kV)										
Overhead Pole Miles	86.08	86.08	86.10	86.10	86.10	85.50	85.50	85.61	85.80	85.80
Underground Circuit Miles	177.17	178.06	179.00	179.00	185.70	194.20	194.20	196.58	199.38	200.06
Street Lights (excluding inactivated lights)(1)	5,470	5,470	6,415	-	-	-	-	-	-	-

(1) Street Lights were transferred to the City of Alameda in FY2018 per Voter approval in November 2016

Fiscal Year	Actual	Budget
2016	236	235
2017	206	230
2018	233	208
2019	278	197
2020	307	186
2021	330	267
2022	397	272
2023	350	202
2024	364	210
2025	388	233

Bond Disclosure Section

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December 4, 2025

Subject: Bond Disclosure Information

We are pleased to provide bond disclosure information for Alameda Municipal Power (AMP), an enterprise fund and department of the City of Alameda, California. The information presented is for AMP's five (5) most recent fiscal years, which includes those ended June 30, 2025, 2024, 2023, 2022, and 2021. AMP believes that the data presented here is accurate in all material respects, that the data is presented in a manner designed to set forth fairly the financial position of the organization and that all disclosures necessary to gain an understanding of the financial activity of AMP are included in this report.

This Bond Disclosure Section is provided to fulfill requirements for an Annual Financial Report, and other information, as required by the:

<u>Continuing Disclosure Certificates for the Alameda Public Financing Authority, Revenue Bonds, Series 2010A/B (Alameda Municipal Power Refinancing).</u>

<u>Continuing Disclosure Certificates obligation for the Bureau of Electricity/City of Alameda with respect to the Northern California Power Agency's revenue bonds:</u>

Geothermal-2016 Series A due 7/1/2024

Hydroelectric-2012 Refunding Series A&B due 7/1/2032
Hydroelectric-2018 Refunding Series A&B due 7/1/2025
Hydroelectric-2022 Refunding Series A due 7/1/2032
Hydroelectric-2022 Refunding Series B due 7/1/2027

Capital Facilities-2019 Refunding Series A due 7/1/2025

Annual Financial Report

This Bond Disclosure Section, included within AMP's Annual Comprehensive Financial Report (ACFR) for Fiscal Years Ended 2025 and 2024, provides the most recent information required by the Continuing Disclosure Certificates (the Certificates). The ACFR, in turn, will be filed with the appropriate Dissemination Agent(s) for transmittal to the repositories in accordance with the requirements of the Certificates. The Annual Financial Report is incorporated into the ACFR and includes by reference the audited financial statements of AMP for the prior fiscal year.

This Bond Disclosure Section incorporated into this fiscal year's ACFR, also contains the following information required by the Certificates:

1. Updated information comparable to the information in the table entitled "City of Alameda, Alameda Municipal Power, Power Supply Resources"
2. Updated information comparable to the information in the table entitled "City of Alameda, Alameda Municipal Power, Electric Rate Changes"
3. Updated information comparable to the information in the table entitled "City of Alameda, Alameda Municipal Power, Electric Customers, Sales, Revenues and Demand"; and,
4. Updated information comparable to the information in the table entitled "City of Alameda, Alameda Municipal Power, Condensed Operating Results and Selected Balance Sheet Information".

Reporting of Significant Events

As of June 30, 2025, none of the events listed in Section 5 of the Certificates have occurred for the Series 2010 A/B bonds issued by the Alameda Public Financing Authority. As of June 30, 2025, Alameda Municipal Power has no knowledge of any impending significant event that would require disclosure under the provisions of the Certificates.

Additional Information

Senate Bill (SB) 1X 2 requires that load serving entities like AMP maintain their percentage of eligible renewable power used to supply their retail end-use customers at no less than an average of 20% for the calendar years (CY) 2011 through 2015, and gradually increasing to 33 percent for 2020. In January 2016 AMP's Public Utilities Board (Board) approved a revised RPS Policy that is consistent with that of the State for the years 2014 through 2021. Since then, more stringent requirements have been adopted in addition to SB X1 2 requirements. In October 2015, SB 350 was signed into law mandating a 33 percent RPS target by 2020 and 50 percent by 2030. In September 2018, SB 100 was signed into law, further accelerating the RPS targets to 50 percent by 2026 and 60 percent by 2030. Starting January 2020, the Board approved and committed to supplying AMP's customers with 100% Carbon-Free Energy and adopted a revised RPS Plan in November 2020 to align with the State's current RPS requirements.

Additionally, AMP's Board approved a Renewable Energy Sales and Use of Resulting Revenues Policy that allowed AMP to sell any eligible renewable power through 2019 not required to comply with AMP's RPS. The resulting revenues from these sales are used to support initiatives to reduce Green House Gas (GHG) emissions associated with electricity use by AMP's customers. AMP established a Board designated reserve in compliance with the policy. AMP sold its share of eligible renewable energy generated by NCPA's Geothermal Project and Ameresco's Ox Mountain LFGE facility from January 2013 to December 2017 to the California Department of Water Resources. Subsequent to the expiration of this contract, AMP negotiated a similar sale to Shell Energy North America from January 1, 2017 – December 31, 2019. Net revenue from the renewable energy sales is held in a designated reserve that is part of a Rate Stabilization Fund and, as such, is not pledged to secure the payment of the 2010 Installment Payments, the payments with respect to any Parity Obligations or any payment with respect to any Subordinate Debt. During fiscal year (FY) 2025, the revenue from the REC sales resulted in an additional $452,162 funding for the program and allocated $1,577,203 for purchased power, capital, and energy efficiency programs from the sales of eligible renewable power (see *Statement of Revenues, Expenses and Changes in Net Position*) toward the Board designated reserve as part of the Rate Stabilization Fund. This allocated net revenue included $16,095,944 of cash and $0 of receivables (see *Statement of Net Position*).

Additionally, the California Cap-and-Trade (C&T) program began implementation of auction sales of directly allocated allowances from the California Air Resources Board (CARB). The resulting revenues from these sales must be used for the benefit of retail ratepayers consistent with the goals of Assembly Bill 32. AMP established a Board designated reserve in compliance with the requirements of these directions. An expenditure plan that complies with current C&T regulations has been reviewed by the Board. Net revenue from auction sales of directly allocated allowances are held in a designated reserve that is part of a Rate Stabilization Fund and, as such, is not pledged to secure the payment of the 2010 Installment Payments, the payments with respect to any Parity Obligations or any payment with respect to any Subordinate Debt. During FY 2025, the revenue from C&T sales resulted in an additional $2,010,849 and allocated $2,000,004 for purchased power (see *Statement of Revenues, Expenses and Changes in Net Position*) toward the Board designated reserve as part of the Rate Stabilization Fund. This allocated net revenue included $1,805,357 of cash and $0 of receivables (see *Statement of Net Position*).

In FY 2025, AMP sold 17,699 Low Carbon Fuel Standards (LCFS) Program credits. The revenue from the sale resulted in an additional $999,994 funding for the program that is administered by CARB. The program is to reduce the carbon intensity of transportation fuels in California by 20 percent by 2030. Pursuant to the California Code of Regulations Sec. 95483(e)(1), LCFS program proceeds may only be used to: benefit current or future EV customers, educate the public on the economic, environmental, and societal values of EV adoption (total cost of ownership compared to gasoline-fueled vehicles), and provide rate options that encourage off-peak charging and minimize grid impacts. Net revenue from auction sales of directly allocated credits are held in a designated reserve that is part of a Rate Stabilization Fund and, as such, is not pledged to secure the payment of the 2010 Installment Payments, the payments with respect to any Parity Obligations or any payment with respect to any Subordinate Debt. During FY 2025, AMP allocated $577,137 for EV capital purchase and EV charger rebates of net revenue from the sale to LCFS sales of directly allocated allowances (see *Statement of Revenues, Expenses and Changes in Net Position)* toward the Board designated reserve as part of the Rate Stabilization Fund. This allocated net revenue included $1,016,150 of cash and $0 of receivables (see *Statement of Net Position*).

Alameda Municipal Power
Power Supply Resources
Year Ended June 30, 2025

Source	Capacity Available (MW)[1]	Actual Energy (GWh)	% of Total Energy
Purchased Power[2]:			
Western Hydroelectric	9.6	32.9	7.7%
Landfill Gas	6.8	50.3	11.8%
High Winds	4.6	15.9	3.7%
Calpine Geysers	2.5	10.9	2.5%
Silicon Valley Power	--	36.3	8.5%
NCPA			0.0%
Hydroelectric Project	24.7	39.8	9.3%
Combustion Turbine Project No. 1 & 2[3]	24.8	3.4	0.8%
Geothermal Plant 1	13.3	30.4	7.1%
Geothermal Plant 2	8.9	33.5	7.9%
Graeagle	--	2.6	0.6%
Other Purchases (Net)	--	171.2	40.1%
Total Capacity and Total Purchased Energy	95.2	427.1	119.6%
AMP's Load	--	369.4	103.4%
Less Line Losses	N/A	(12.1)	-3.4%
AMP’s Capacity and Retail Sales Requirements	67.2	357.2	100.0%

[1] Non-coincident, maximum net qualifying capacity available for CAISO.

[2] Entitlements, firm allocations and contract amounts.

[3] Combustion Turbine Project No. 2 is also referred to as Unit One or the Project in the front part of this Official Statement. See “THE PROJECT” in the front part of this Official Statement.

Source: Alameda Municipal Power

Alameda Municipal Power
Electric Rate Changes
Last Ten Fiscal Years

Electric Rate Changes

Date	Percent Change	
July 1, 2016	5.00%	
July 1, 2017	5.00%	
July 1, 2018	1.00%	
July 1, 2019	2.50%	
July 1, 2020	0.00%	
July 1, 2021	0.00%	
July 1, 2022	5.00%	
July 1, 2023	7.00%	
July 1, 2024	3.00%	
July 1, 2025	4.00%	(Fiscal Year 2026)

Description	2021	2022	2023	2024	2025
Number of Customers Accounts:					
Residential	31,937	32,058	33,850	33,711	32,877
Commercial	3,870	3,854	3,894	3,810	3,813
Industrial	10	11	9	15	20
Public Authority	359	348	361	350	351
Other	25	14	16	9	9
Total Customers	36,201	36,285	38,130	37,895	37,070
Kilowatt Hour Sales:					
Residential	138,607,950	130,100,333	142,845,315	135,285,528	139,424,569
Commercial	146,664,721	150,731,047	160,854,387	167,903,386	168,243,579
Industrial	35,641,270	31,576,810	31,982,570	28,368,710	37,107,650
Public Authority	10,470,953	12,536,267	12,541,574	12,555,799	12,566,651
Other	2,548,136	1,763,268	2,307,674	1,912,228	1,705,736
Total kWh sales	333,933,030	326,707,725	350,531,520	346,025,651	359,048,185
Revenues from Sale of Energy:					
Residential	$27,946,417	$26,375,111	$29,742,058	$30,590,103	$32,679,325
Commercial	26,015,342	26,584,210	29,670,943	32,733,484	33,702,969
Industrial	5,845,303	5,230,140	5,493,443	5,256,043	7,060,102
Public Authority	2,058,753	2,455,536	2,536,925	2,722,668	2,791,253
Other	320,052	15,350	970,954	981,614	292,019
Total Revenues from Sale of Energy	$62,185,867	$60,660,347	$68,414,323	$72,283,912	$76,525,668
Peak Demand (kW)	62,664	60,551	64,002	60,014	67,239

Alameda Municipal Power

Condensed Operating Results and Selected Balance Sheet Information

Through the Fiscal Year Ended June 30,

Description	2021	2022	2023	2024	2025
Electric System Revenues					
Sales of Electricity	62,185,866	60,660,347	68,414,323	72,283,912	76,525,668
Other Revenues (1)	2,063,225	3,473,624	2,790,995	2,663,241	3,458,580
REC & LCFS & C&T Sales(6)	2,296,903	2,165,206	1,765,255	3,179,665	1,936,640
Total Electric System Revenues	66,545,994	66,299,177	72,970,573	78,126,818	81,920,888
Operation and Maintenance by FERC categories					
Purchased Power (2)	30,296,114	33,920,081	36,101,823	35,696,806	32,416,136
Energy efficiency, solar and other	1,331,638	1,217,122	1,401,353	1,637,182	1,317,000
Operations & maintenance	5,524,880	5,260,275	6,124,728	8,104,162	9,831,397
Customer service, information systems	3,177,863	3,017,424	3,179,479	3,113,980	3,406,570
Administrative and general	8,158,825	698,303	9,641,760	11,854,975	10,797,776
Customer relations	449,614	390,657	409,533	400,463	481,324
Jobbing sales expense	1,646,595	2,822,759	1,985,502	1,874,528	1,202,689
Balancing account adjustment	6,680,252	2,464,533	5,277,979	6,115,571	10,037,672
Total Operation and Maintenance Costs	57,265,781	49,791,154	64,122,157	68,797,667	69,490,564
Net Revenues	9,280,213	16,508,023	8,848,416	9,329,151	12,430,324
Rate Stabilization Fund Transfers	(2,296,903)	(2,165,206)	(1,765,255)	(3,179,665)	(3,458,580)
Use of Reserves	3,673,585				
Adjusted Annual Net Revenues	10,656,895	14,342,817	7,083,161	6,149,486	8,971,744
Debt Service (Principal + Interest)	2,646,470	2,603,327	2,614,055	2,607,940	2,599,656
Debt Service Coverage (3)	4.03	5.51	2.71	2.36	3.45
Amount Available After Debt Service	8,010,425	11,739,490	4,469,106	3,541,546	6,372,088

Selected Balance Sheet Information (in thousands):

Unrestricted Cash & Investments (4)	70,496	72,759	71,438	78,518	92,443
Rate Stabilization Fund Balance (6)	23,804	21,410	18,942	18,497	18,917
Net Plant in Service	32,962	32,051	29,494	28,367	29,108
Construction Work in Progress	3,006	3,729	6,316	7,700	13,913
Electric Utility Plant-Net	35,968	35,780	35,810	36,067	43,021
Outstanding Electric System Debt(5)	20,045	18,560	16,960	15,255	13,440

(1) Other Revenues includes operating and non-operating sources such as solar surcharge, interest income from investments, lease income, account establishment, reconnection and late fees, jobbing sales, and other miscellaneous items.

(2) Includes purchased power costs, payments to NCPA and TANC and prior year budget settlements from NCPA.

(3) Adjusted Annual Net Revenues divided by debt service.

(4) Includes General Reserve balance held at NCPA. See also "Available Reserves" below.

(5) During August 2010, AMP refinanced its 2000A/AT debt. The resulting 2010A/B revenue bonds had an initial book-entry principal of $31,685,000, or $7,360,000 less than the 2000A/AT debt. This advance refunding was undertaken to reduce debt service payments over the next 20 years by $17,662,628 and resulted in an economic gain of $2,308,432. In FY2014, AMP adopted GASB No. 65 and excluded the advance refunding from "Oustanding Electric System Debt" , see Note 4 to Financial Statements

(6) Includes Renewable Energy Sales and Auction Sales for Cap & Trade & Low Carbon Fuel Sales (LCFS) placed into reserve for Rate Stabilization Fund.

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INDEPENDENT AUDITOR'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

To the Public Utilities Board
Alameda Municipal Power
Alameda, California

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the basic financial statements of Alameda Municipal Power (AMP) (California), as of and for the year ended June 30, 2025, and have issued our report thereon dated December 4, 2025. Our report included an emphasis of a matter paragraph disclosing the implementation of new accounting principles.

Report on Internal Control over Financial Reporting

In planning and performing our audit of the financial statements, we considered AMP's internal control over financial reporting (internal control) as a basis for designing audit procedures that are appropriate in the circumstances for the purpose of expressing our opinions on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of AMP's internal control. Accordingly, we do not express an opinion on the effectiveness of AMP's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of AMP's financial statements will not be prevented, or detected and corrected on a timely basis. A *significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses or significant deficiencies may exist that have not been identified.

Accountancy Corporation
3478 Buskirk Avenue, Suite 217
Pleasant Hill, CA 94523

T 925.228.2800
E maze@mazeassociates.com
W mazeassociates.com

Report on Compliance and Other Matters

As part of obtaining reasonable assurance about whether AMP's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the financial statements. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance that are required to be reported under *Government Auditing Standards*.

We have also issued a separate Memorandum on Internal Control dated December 3, 2025, which is an integral part of our audit and should be read in conjunction with this report.

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of AMP's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering AMP's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

Maze + Associates

Pleasant Hill, California
December 3, 2025

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

AGENDA ITEM NO.: 4.F.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: 2026-40
ACTION: BY MOTION

To: Honorable Public Utilities Board

Submitted by: /S/
Teri Alderson
GM-Administration

From: Heather Heinbaugh
Finance and Utility Billing Manager

Approved by: /S/
Tim Haines
General Manager

Subject: By Motion, Recommend City Council Approve the Upgrade of One Customer Service Representative Position to Lead Customer Service Representative Classification, the Upgrade of the Procurement Analyst Classification to Senior Procurement Analyst, and the Reclassification of Senior Clerk to Administrative Services Coordinator, and Find the Action Exempt from the California Environmental Quality Act

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RECOMMENDATION

By motion, find AMP's action is not a CEQA project pursuant to CEQA Guidelines Section 15378, is exempt from the California Environmental Quality Act pursuant to CEQA Guidelines Sections 15061(b)(3) and 15378 for the reasons outlined in the administrative report, and recommend City Council approve the upgrade of one Customer Service Representative position to Lead Customer Service Representative classification, the upgrade of the Procurement Analyst classification to Senior Procurement Analyst, and the reclassification of Senior Clerk to Administrative Services Coordinator.

BACKGROUND

Alameda Municipal Power (AMP) is committed to employee retention through clear developmental pathways that support succession planning and operational continuity. The City of Alameda's Human Resources department worked with AMP staff and the Electric Utility Professional of Alameda (EUPA) to establish a new Senior Procurement Analyst classification and update the Lead Customer Service Representative classification, both of which were approved by the Civil Service Board on October 8, 2025. In addition, AMP is proposing reclassifying one existing Senior Clerk position to Administrative Services Coordinator to better align with the duties currently being performed and to support increased coordination between the Engineering and Operations teams.

DISCUSSION

The proposed upgrade from Procurement Analyst to Senior Procurement Analyst reflects the growing complexity of AMP's procurement needs. The Senior Procurement Analyst will take on greater responsibility for managing formal solicitations and overseeing more complex procurement activities. This change allows procurement work to be handled with greater independence while enabling the Support Services Manager, which oversees this position, to focus on broader, facilities-related operational priorities. Establishing this classification also supports employee development and creates a clear advancement path within the procurement function.

The proposed conversion of one Customer Service Representative position to the Lead Customer Service Representative classification addresses the need for additional leadership within the Customer Service team. The Lead position will provide day-to-day support to staff and assist with training and issue resolution. Adding this structure will allow supervisors to focus on performance management and process improvements, while maintaining consistent and responsive customer service. This new role establishes a defined career pathway for customer service staff, supporting retention and service continuity. Additional classification changes may be considered in future budget cycles as AMP continues to modernize customer service and billing operations.

The proposed reclassification of Senior Clerk to Administrative Services Coordinator reflects the evolution of the position over time. The role supports the Operations team by maintaining records, coordinating administrative workflows, and assisting with procurement activities. The position currently serves as a back-up to the existing Engineering and Operations administrative role, and the proposed reclassification formalizes these responsibilities. The position also plays an important role in supporting coordination between the Engineering and Operations teams, particularly around work order processing and close-outs. This change will improve that coordination and reduce work order delays. Without the reclassification, staff anticipates continued inefficiencies and a lower level of service due to limited administrative capacity.

AMP’s Position Control is maintained by the City, therefore, implementation of the proposed classification changes requires City Council approval. AMP staff is seeking a recommendation from the Public Utilities Board that City Council approve the proposed classification changes.

FINANCIAL IMPACT

AMP has sufficient funds in the fiscal year (FY) 2026 budget and will include funds in the proposed FY 2027 budget.

ENVIRONMENTAL REVIEW

Alameda Municipal Power finds that its actions are not a project as defined by CEQA Guidelines Section 15378, which excludes “continuing administrative or maintenance activities, such as purchases for supplies, personnel-related actions, general policy and procedure making” and “organization or administrative activities of governments…” Alameda Municipal Power further finds that it can be seen with certainty that there is no possibility that the activity will result in a direct or reasonably foreseeable indirect change in the environment. The project involves the reclassification of three full-time positions, and there is no potential for direct or indirect changes in existing conditions as a result.

Alameda Municipal Power further finds that its actions are exempt from CEQA, including but not limited to CEQA Guidelines Section 15061(b)(3). More specifically, Alameda Municipal Power finds its actions are subject to the commonsense exemption because it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

LINK TO STRATEGIC PLAN AND METRICS

Customer Experience, Strategy 3: AMP will maximize opportunities to meet customer needs.

Workforce Strategy: AMP will attract and retain employees while fostering a collaborative culture and adapting to changes in industry trends.

EXHIBITS

None.

AGENDA ITEM NO.: 4.G.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: 2026-41
ACTION: BY MOTION

To: Honorable Public Utilities Board

Submitted by: /S/
Alan Harbottle
Acting AGM - Engineering & Operations

From: Alan Harbottle
Acting AGM - Engineering & Operations

Approved by: /S/
Tim Haines
General Manager

Subject: By Motion, Authorize the Purchase of One Brooks Brothers Three-Reel Trailer for an Amount Not to Exceed $136,600 and Find the Action Exempt from the California Environmental Quality Act

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RECOMMENDATION

By motion, find AMP's action is exempt from the California Environmental Quality Act pursuant to CEQA Guidelines Sections 15061(b)(3) and 15378 for the reasons outlined in the administrative report, and authorize the purchase of one Brooks Brother three-reel trailer for an amount not to exceed $136,600.

BACKGROUND

Alameda Municipal Power (AMP) utilizes a three-reel trailer for the efficient deployment of conductors to jobsites and to aid in installation and removal. AMP's Reelstrong MRT3-8K 2016 three-reel turret utility trailer is permanently out of service. The three-reel trailer was identified in AMP's Vehicle Replacement Schedule for purchase in fiscal year 2026 (FY).

DISCUSSION

Currently, the installation of long three-phase spans of conductor requires multiple trips to and from the AMP Service Yard to load and unload reels. Staff anticipates significant reconductoring work over the coming years, between plans to address open secondaries, #6 Copper spans, and additional capacity identified in the AMP whole system study. The three-reel trailer can better aid in emergency restoration efforts as it can be loaded with different types of wire, allowing a single truck to arrive on-site with every possible material needed to restore power.

AMP is sourcing from a competitively bid cooperative contract through Sourcewell for a Brooks Brothers 3TRT 242 – 15KE Galvanized Trailer for an amount not to exceed $136,600 including taxes.

FINANCIAL IMPACT

AMP has sufficient funds in its FY 2026 budget to purchase the three-reel trailer with a budget transfer of the remaining funds from the Cable Puller line item.

Note, the not-to-exceed amount is $1,000 higher than that listed in the Vehicle Replacement Schedule due to a sales tax calculation error.

ENVIRONMENTAL REVIEW

Alameda Municipal Power finds the purchase of one Brooks Brother three-reel trailer is not a project as defined by CEQA Guidelines Section 15378, which excludes "Continuing administrative or maintenance activities, such as purchases for supplies." AMP's action involves the replacement of an out-of-service fleet vehicle. Alameda Municipal Power further finds that it can be seen with certainty that there is no possibility that the activity will result in a direct or reasonably foreseeable indirect change in the environment.

Alameda Municipal Power further finds that its actions are exempt from CEQA, including but not limited to CEQA Guidelines Section 15061(b)(3). More specifically, Alameda Municipal Power finds its actions are subject to the commonsense exemption because it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment. Alameda Municipal Power's actions involve the purchase of one Brooks Brother three-reel trailer.

LINK TO STRATEGIC PLAN AND METRICS

Business Resiliency, Strategy 1: AMP will develop an asset management plan to guide efficient capital and maintenance expenditures which improve system operations and resiliency.

EXHIBIT

A. Sourcewell Quote

AGENDA ITEM NO.: 4.G
MEETING DATE: 01/12/2026
EXHIBIT A

Altec Industries, Inc.

Quote Number:	1815500
Opportunity Number:	25154592
Sourcewell Contract #:	110421-ALT
Date:	5/21/2025

Quoted for: Alameda Municipal Power (AMP)

Customer Contact: Steve Gee
Phone: / Email: 661-477-9720 / sgee@alamedamp.com

Quoted by: CiJay Smith
Phone: / Email: 816-244-8394 / cijay.smith@altec.com
Altec Account Manager: John Widenmann

REFERENCE ALTEC MODEL		**Sourcewell Price**
WORK-TRAILERS	**Trailers Sourced by Altec Work Truck**	**$116,849**

(A.) SOURCEWELL OPTIONS ON CONTRACT (Unit)

1			
2			
3			
4			

(A1.) SOURCEWELL OPTIONS ON CONTRACT (General)

1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
		SOURCEWELL OPTIONS TOTAL:	$116,849

(B.) **OPEN MARKET ITEMS** *(Customer Requested)*

1	UNIT	Brooks Brothers 3TRT 242 - 15KE Galvanized	$0
2	UNIT & HYDRAULIC ACC		$0
3	BODY		$0
4	BODY & CHASSIS ACC		$0
5	ELECTRICAL		$0
6	FINISHING		$0
7	CHASSIS		$0
8	OTHER		$0
		OPEN MARKET OPTIONS TOTAL:	$0

SUB-TOTAL FOR UNIT/BODY/CHASSIS:	**$116,849.00**
Delivery	**$7,000.00**
FET:	**$14,021.88**

Note: AMP does not pay FET

TOTAL FOR UNIT/BODY/CHASSIS:	**$137,870.88**

(C.) **ADDITIONAL ITEMS** (items are not included in total above)

1			
2			
3			
4			

Pricing valid for 45 days

AGENDA ITEM NO: 5.A.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: 2026-42
ACTION: BY MOTION

To: Honorable Public Utilities Board

Submitted by: /S/
Chris Ferrara
AGM – Customer Resources

From: Alan Harbottle
Supervisor Energy Resources

Approved by: /S/
Tim Haines
General Manager

Subject: By Motion, Accept Alameda Municipal Power's Load Forecast for Fiscal Year 2027, and Find the Action Exempt from the California Environmental Quality Act

RECOMMENDATION

By *motion*, find AMP's action is not a CEQA project pursuant to CEQA Guidelines Section 15378, is exempt from the California Environmental Quality Act pursuant to CEQA Guidelines Sections 15061(b)(3) and 15378 for the reasons outlined in the administrative report, and accept Alameda Municipal Power's Load Forecast for fiscal year 2027.

BACKGROUND

Each year, Alameda Municipal Power (AMP) staff prepares a forecast of the peak demand and energy requirements (load forecast) for the next 10 years. Staff relies on the load forecast in developing AMP's budget and rates for the upcoming fiscal year. In addition to the fiscal year (FY) 2027 budget, AMP staff will use the FY 2027 load forecast for the following:

- Projecting AMP's finances with the 10-year pro forma financial model
- Developing Northern California Power Agency's (NCPA) annual budget and pre-billing of monthly power costs
- Complying with California's Renewable Portfolio Standards (RPS) and other environmental regulations

This report presents forecast results for Most Likely, High, and Low scenarios. Results for the Most Likely scenario represent staff's best projection of AMP's customer energy usage based on currently available information. The High and Low scenarios are used to examine the impacts of high and low load conditions and bracket the Most Likely scenario. This report provides a summary of the FY 2027 load forecast, the methodology used in preparation of the forecast, a detailed look into individual rate classes, and a comparative analysis of recent forecasts.

DISCUSSION

Summary of the FY 2027 Load Forecast

The FY 2027 load forecast uses recent trends of energy sales, losses, and assumptions for various load modifiers such as customer growth, distributed generation (DG), electric vehicles

(EVs), energy efficiency (EE), and electrification (i.e. switching fuel sources in buildings to electricity) to forecast sales and load for each customer class for a 10-year period. The assumptions for customer growth are based on staff's projections for future residential and commercial development in Alameda. Figure 1 shows actual and forecast load over a 10-year period by customer class.

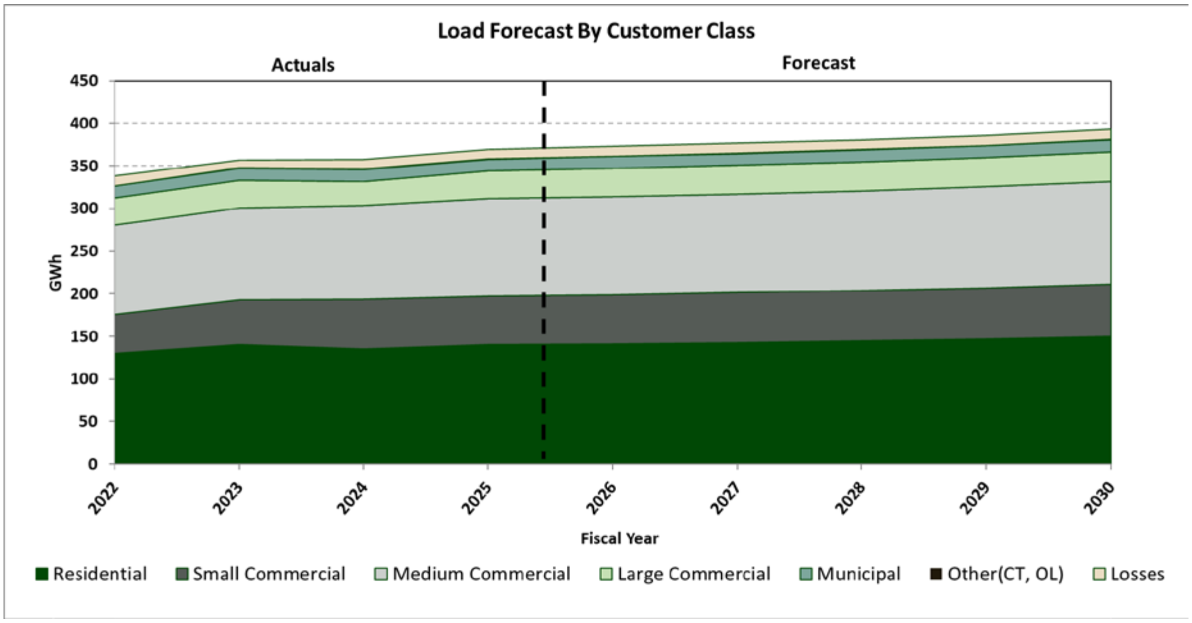


Figure 1: Actual Load and Most Likely Scenario

Actual load data through mid-FY 2026 reveals small year-to-year variations slowly increasing beyond 350 gigawatt hours (GWh) per year. In FY 2025, AMP exceeded its forecast by 1.4 percent, driven by gains in the commercial sectors. The FY 2026 forecast is lagging behind actuals and has been revised upwards 2 percent in the FY 2027 forecast. Current power demand remained stable over the period, despite signs of an economic slowdown in the residential development, commercial office space, and biotech sectors. The FY 2027 forecast starts off higher with adjustments to the baseline following most recent actuals, but overall maintains similar growth projections to the FY 2026 forecast moving forward. In FY 2028 and beyond, the largest new impact to the Likely Forecast scenario is the impact of SF Bay Ferry charging. SF Bay Ferry has proposed installing electric chargers in Alameda for a new, battery-electric ferry fleet. In the near-term, new development is expected to drive growth between 1 and 2 percent. After FY 2031, load is expected to return to a slower rate of growth for the remainder of the forecast period, averaging approximately 0.9 percent per year.

Figure 2 illustrates the three load growth scenarios (Most Likely, High, and Low) from the current fiscal year through FY 2034. The scenarios are affected by assumptions for new developments, electrification, DG, EE, and EVs. In particular, the High forecast scenario has a large increase in FY 2028–2030 to reflect that AMP has continued to receive speculative interest from multiple parties about upgrading Alameda Point buildings for high power needs of around 10 megawatts (MW) baseload.

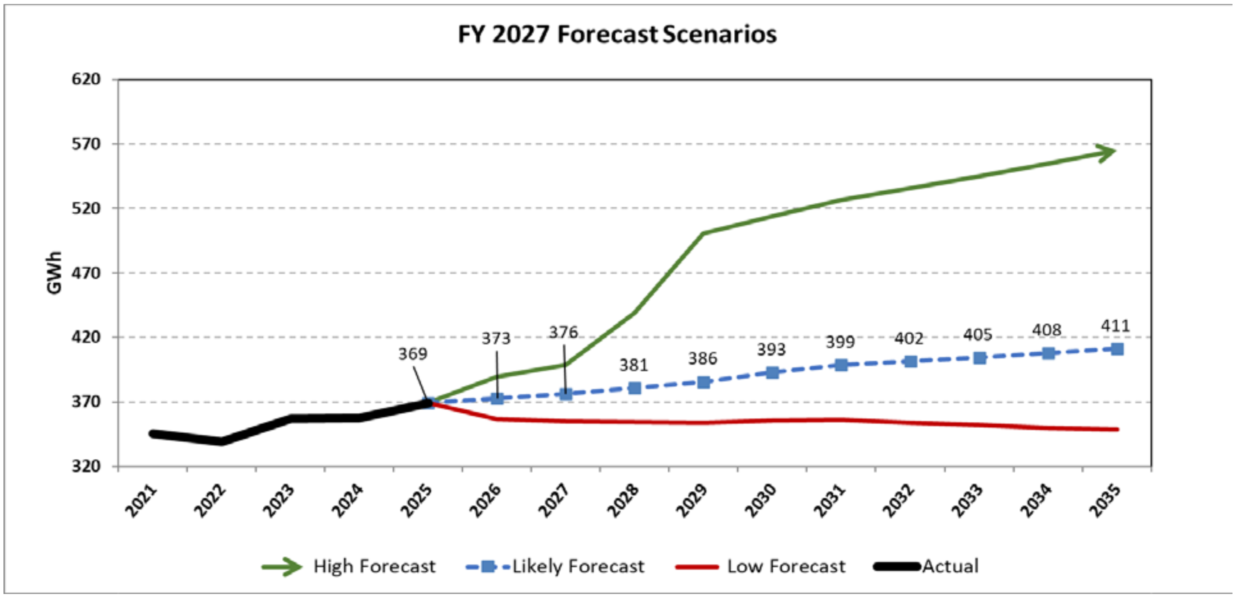


Figure 2: 10-Year Load Forecast Scenarios

Figure 3 compares the Most Likely load forecast for the current and previous two fiscal years. FY 2027 largely tracks the FY2026 forecast, with the most recent actuals increasing the starting point. The adjustments to the baseline represented the most year-over-year change in the FY 2027 forecast with small adjustments in New Developments, EVs, DG, EE, and electrification to align with the latest observed trends.

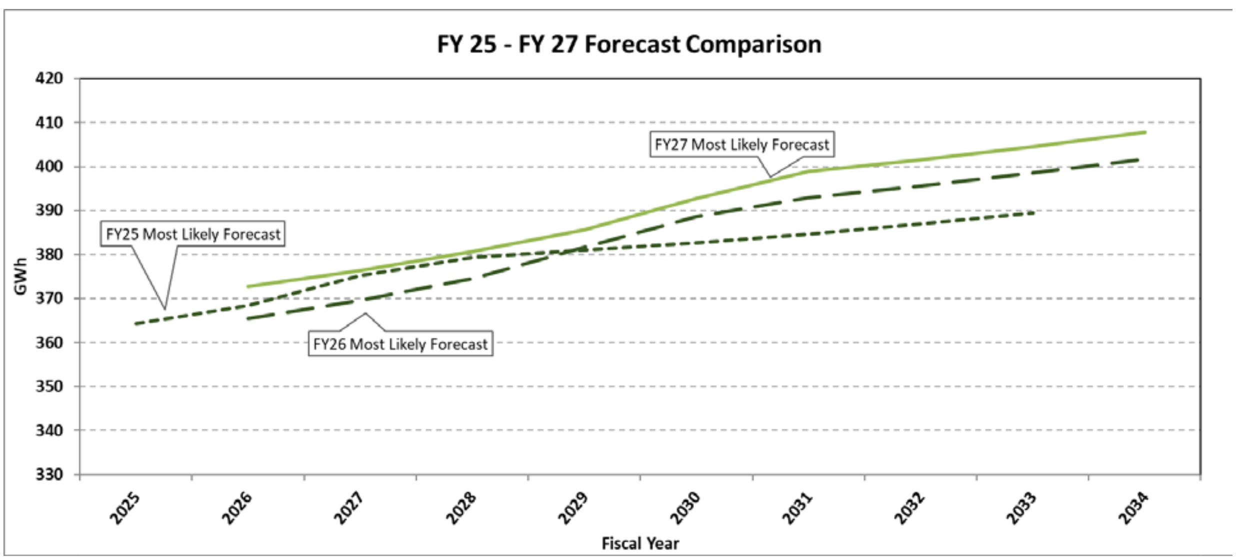


Figure 3: Fiscal Year (FY) 2027 and Prior FY Load Forecasts, Most Likely Scenario

Load Forecast Methodology

AMP staff continues to follow the same forecasting methodology as in years past, with a few modifications to improve accuracy. Staff begins with the preceding year's load/sales actuals as the base load in the forecast. The following years' forecast is then modified based on various factors affecting load, like new development, EE, DG, EVs, and electrification.

Factors Affecting Short-Term Load Forecast

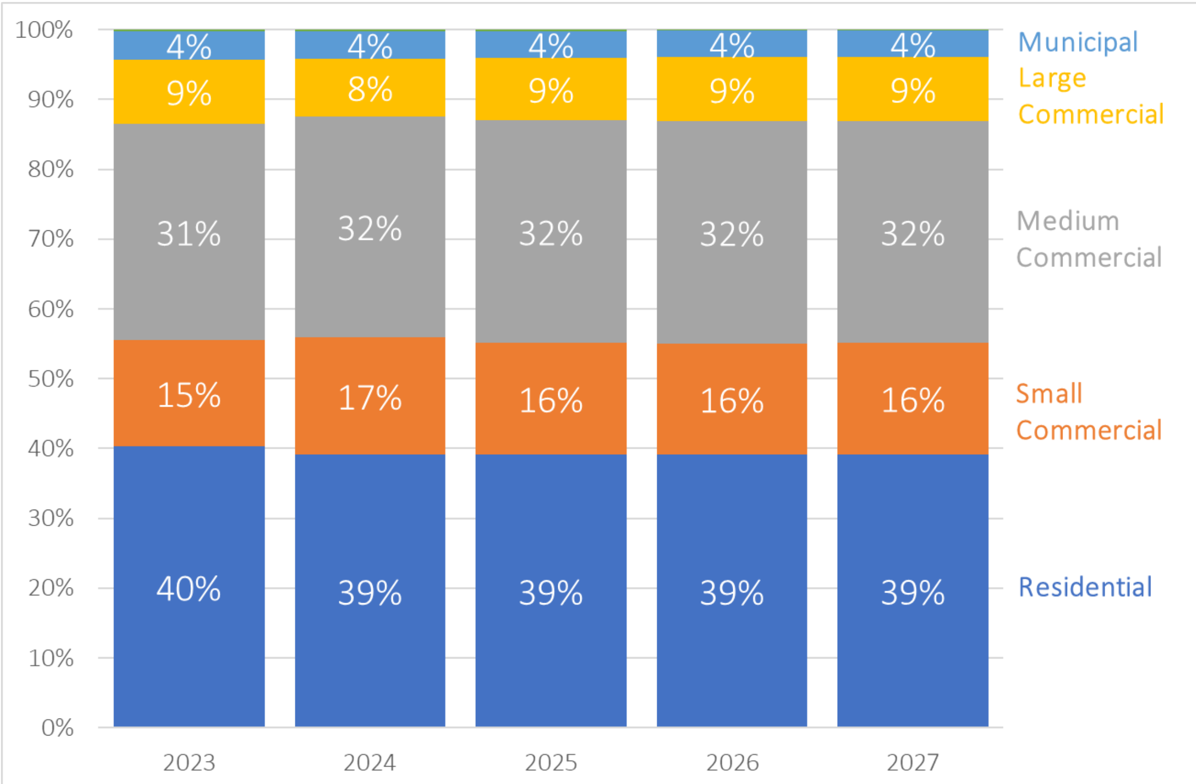


Figure 4: Fiscal Years 2023–2027 AMP Load Share by Customer Class, Percent

Residential Class Forecast

AMP has two residential customer classes: D-1, for individually metered dwellings, and D-2, for multi-family dwellings with a single meter. The D-1 class accounts for more than 98 percent of all residential customer load. The D-2 class is closed to new customers.

To forecast the load for the D-1 class, AMP forecasts the number of new customers in each year of the 10-year period. To accomplish this, AMP staff consults with the City's Planning, Building, and Transportation Department's (PBT) Development Forecast and Base Reuse and Economic Development Department (BRED), AMP's own engineering and key accounts management personnel, and reviews relevant City Council reports and news articles to develop a forecast of new residential developments.

Table 1 has actual and forecast Most Likely Scenario data from the FY 2027 load forecast for number of customers and usage per customer. Customer growth is based on residential new development forecasts for the number of new units. After staff forecasts the base load for D-1 customers from the projected number of new customers and the forecast usage per customer, additional factors that affect customer load are applied, which are discussed below.

Table 1: New Customers and Usage, Most Likely Scenario

	Actual		Fiscal Year 2027 Forecast					
	2024	2025	2026	2027	2028	2029	2030	2031
Total Customers	32,979	32,746	32,831	33,022	33,164	33,532	34,079	34,273
New Customers			85	191	142	368	547	194
(kWh/customer/year)	4,038	4,192	4,236	4,261	4,295	4,319	4,340	4,376

Table 2 highlights some of the major developments slated to either come online or come to full load in the next five years.

Table 2: Residential Customer Growth by Area

Area	Details	New Units	Time frame
Alameda	Alameda Marina Phase 2	125	2026-2028
Alameda	West Midway/RESHAP	400	2027-2030
Alameda	Pennzoil Project	45	2026-2028

Figure 5 illustrates the total contribution of the additional factors affecting residential sales through the FY 2031 forecast period using the Most Likely Scenario, relative to the updated forecast for total residential sales in FY 2026. The forecast residential sales are expected to increase, driven by the continued growth in occupation of the new developments across the island. EVs and electrification are forecast to continue to grow in importance.

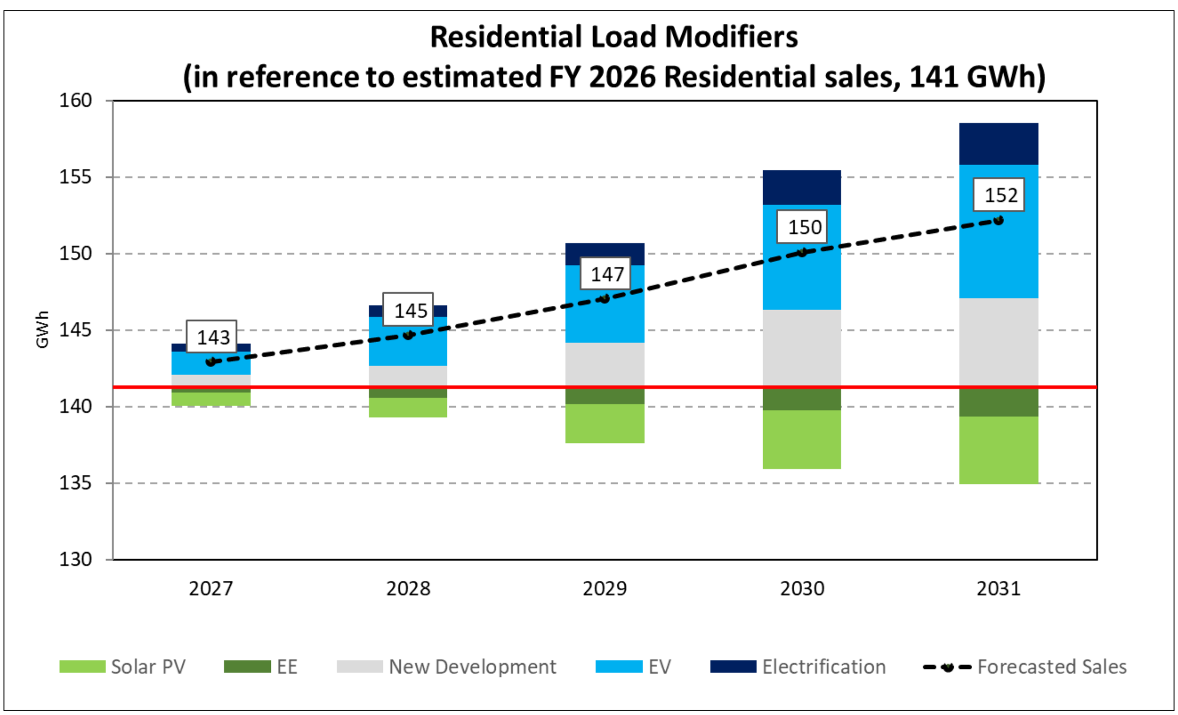


Figure 5: Factors Affecting Residential Load Forecast

Commercial Class Forecast

AMP has four commercial rate classes (A-1, A-2, A-3, and A-4). Monthly customer usage and demand determines which rate class each entity is enrolled into. Currently, AMP does not have any A-4 customers. Table 3 shows the actual sales in FY 2025, followed by forecast sales for the commercial classes for the next five years.

Table 3: Forecast Sales by Commercial Class, Fiscal Years 2025–2030

Fiscal Year	Sales (GWh)			Total Sales (GWh)
	A-1	A-2	A-3	
2025	57.4	114.2	32.2	203.8
2026	57.7	114.8	33.3	205.8
2027	58.4	115.8	33.5	207.7
2028	59.2	117.0	33.9	210.1
2029	60.1	118.2	34.3	212.6
2030	61.5	120.1	34.8	216.4

To project commercial load, the forecast starts with the total commercial load through mid-FY 2026, then subtracts the incremental load reductions from EE and solar PV installations and adds the incremental load from new development and EVs.

Figure 6 illustrates the total impacts of the load modifiers of commercial load through FY 2031 under the Most Likely Scenario. In relation to the revised commercial sales forecast in FY 2026, the three commercial classes are expected to grow primarily as a result of new development.

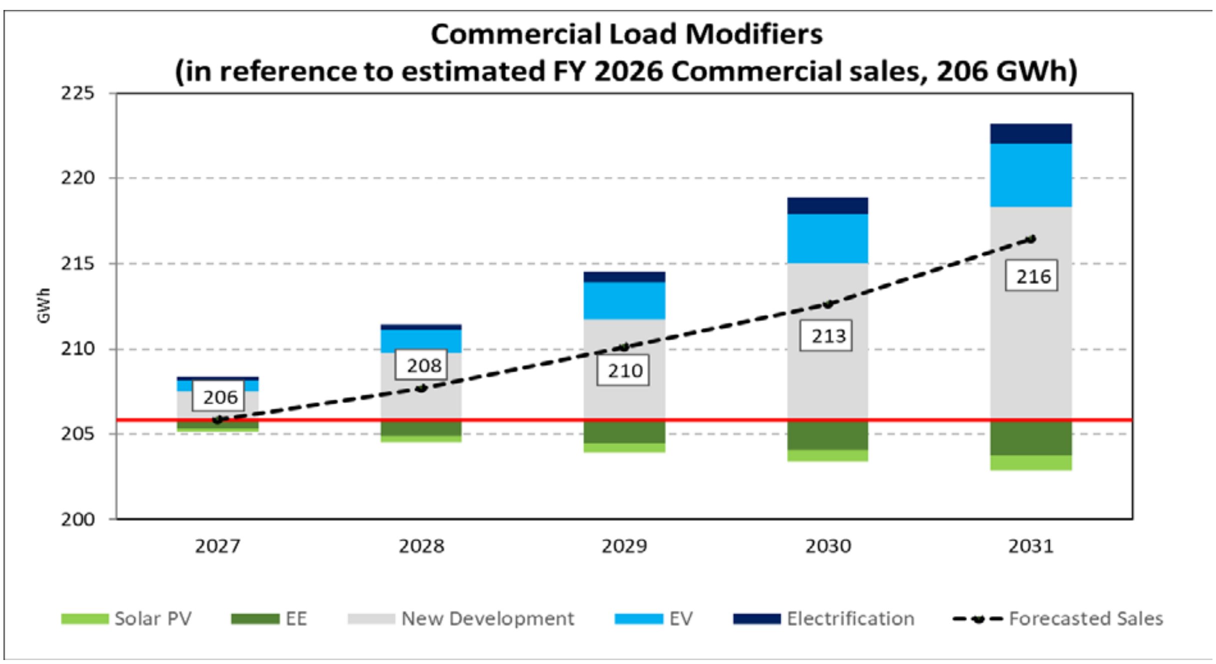


Figure 6: Factors Affecting Commercial Load Forecast

New Development

The principal driver of commercial customer sales is new development. The forecast is compiled using the PBT Development Forecast, input from BRED and AMP engineering and key accounts management staff, and load assumptions from comparable existing customers. Staff expects the primary driver of commercial load growth to be the addition of SF Bay Ferry electric ferry charging. Additionally, the Hilton Garden Inn on Bay Farm Island is nearly ready to be energized and should be opening in early calendar year 2026. More difficult to forecast, but observed in recent years, is a steady stream of smaller upgrades to many A1 and A2 customers that increase usage. Floor space growth over the next five years is expected to be modest and high levels of vacant commercial retail and biotech space throughout the bay area may still lead to some customer departures. Table 4 displays some of the larger proposed commercial developments in the load forecast. The High Usage Customer, assumed to be 10MW baseload, is only included in the High forecast scenario as a possible development given the current speculative nature of interest.

Table 4: Commercial Development

Area	Details	Time Frame
Harbor Bay Business Park	North Loop Rd, 5 Office Buildings	2021-2026
Bay Farm	Hilton Garden Inn	2026-2027
Alameda Point	Enterprise District – Industrial/R&D	2027-2030
Alameda	Electric Ferry Charging	2028-2033
Alameda Point	High Forecast Scenario: High Usage Customer (10MW)	2028-2030

Forecast for Other Customer Classes

The remaining customer classes include municipal accounts (M-1, M-2, and M-3), privately owned outdoor lighting (OL), and service for the two Northern California Power Agency (NCPA) combustion turbine units (CT). M-1 consists of all municipal accounts including Alameda Unified School District (AUSD), with the exception of municipal street lighting (M-2) and AMP's operations (M-3). The forecast sales for these customer classes for FY 2027 is 14.3 GWh, approximately 4 percent of AMP's total sales. Staff keeps power demand for these customer classes flat for the forecast period.

Comparing Recent Energy Forecasts

Prior to FY 2023, actual annual load was lower than forecast, particularly in FY 2021 and FY 2022, the years most impacted by Covid-19. Starting in FY 2023, and continuing through FY 2025, load bounced back and continued to grow beyond expectations. Through mid-FY 2026, load is 188 GWh. Table 5 provides a comparison of the forecast and actual loads for four prior fiscal years and the year-to-date (YTD) forecast for the current fiscal year.

Table 5: Fiscal Year Forecast Annual Load vs. Actual Annual Load

Fiscal Year	Forecast Load (GWh)	Actual Load (GWh)	% Difference
2022	354	338	-4.34%
2023	348	357	2.37%
2024	351	358	1.86%
2025	364	369	1.37%
2026 (YTD)	366 (185)	188	1.61%

FINANCIAL IMPACT

This load forecast does impact the upcoming budgeting process, the development of AMP's revenue requirements for ratemaking updates, and future analysis of resource acquisitions and other longer-term activities.

ENVIRONMENTAL REVIEW

Alameda Municipal Power finds that its actions are not a project as defined by CEQA Guidelines Section 15378, which excludes "continuing administrative…activities" and "organization or administrative activities of governments…" Alameda Municipal Power further finds that it can be seen with certainty that there is no possibility that the activity will result in a direct or reasonably foreseeable indirect change in the environment. The project involves the disclosure of factual information pursuant to statutory mandates, and there is no potential for direct or indirect changes in existing conditions as a result.

Alameda Municipal Power further finds that its actions are exempt CEQA pursuant to CEQA Guidelines §§ 15268, which excludes ministerial actions. More specifically, Alameda Municipal Power finds its action is subject to the commonsense exemption because it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

NEXT STEPS

Staff will develop the FY 2027 forecasts of power costs and revenues at current rates for use in AMP's FY 2027 budgeting process.

LINKS TO STRATEGIC PLAN AND METRICS

Sustainability, Strategy 2: Deliver and maintain 100 percent carbon-neutral energy resources by 2020
Business Resiliency, Strategy 2: Develop financial planning processes that provide fiscal stability

EXHIBITS

A. FY 2027 Most Likely Scenario Load Forecast
B. FY 2027 Load Forecast PowerPoint Presentation

AGENDA ITEM NO.: 5.A
MEETING DATE: 01/12/2026
EXHIBIT A

Alameda Municipal Power
Most Likely Energy Forecast FY2027
1/5/2026

Monthly Energy Forecast (millions of kilowatt-hours):

FY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	10-Year Annual Growth Rate
Jul	29.4	29.6	30.0	30.3	30.8	31.2	31.5	31.8	32.1	32.4	32.8	33.1	33.4	33.8	34.1	34.5	
Aug	30.9	31.2	31.4	31.7	32.3	32.7	33.0	33.3	33.5	33.8	34.2	34.6	34.9	35.2	35.6	35.9	
Sep	31.3	31.6	31.9	32.2	32.8	33.2	33.4	33.7	34.0	34.2	34.7	35.0	35.3	35.6	35.9	36.3	
Oct	31.3	31.6	32.0	32.3	32.9	33.4	33.7	34.1	34.4	34.7	35.1	35.5	35.8	36.2	36.6	36.9	
Nov	31.1	31.4	31.8	32.2	32.8	33.2	33.5	33.8	34.1	34.4	34.8	35.1	35.5	35.8	36.2	36.5	
Dec	35.4	35.8	36.2	36.6	37.2	37.7	38.1	38.5	38.8	39.1	39.6	40.0	40.4	40.8	41.2	41.6	
Jan	34.7	35.1	35.5	36.1	36.8	37.5	37.7	37.9	38.2	38.5	39.0	39.4	39.8	40.2	40.6	41.0	
Feb	30.6	30.9	31.3	31.8	32.4	33.0	33.2	33.4	33.7	34.0	34.4	34.7	35.1	35.4	35.8	36.2	
Mar	32.0	32.3	32.7	33.2	33.8	34.4	34.6	34.8	35.1	35.4	35.9	36.2	36.6	37.0	37.4	37.8	
Apr	28.8	29.1	29.4	29.8	30.4	30.9	31.0	31.2	31.4	31.6	32.0	32.3	32.6	32.9	33.2	33.5	
May	29.1	29.3	29.7	30.2	30.8	31.3	31.5	31.6	31.9	32.2	32.6	32.9	33.2	33.6	33.9	34.3	
Jun	28.3	28.5	28.8	29.3	29.8	30.3	30.4	30.5	30.7	31.0	31.3	31.6	31.9	32.2	32.5	32.8	
FYear	**372.8**	**376.4**	**380.7**	**385.7**	**392.8**	**398.9**	**401.6**	**404.5**	**407.7**	**411.2**	**416.4**	**420.3**	**424.4**	**428.6**	**432.9**	**437.2**	**1.11%**
Check																	
Growth		**0.96%**	**1.14%**	**1.33%**	**1.84%**	**1.54%**	**0.68%**	**0.74%**	**0.79%**	**0.84%**	**1.28%**	**0.93%**	**0.96%**	**0.99%**	**1.01%**	**0.99%**	

Annual Energy Sales by Customer Class (millions of kilowatt-hours):

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	
D-1	139.1	140.7	142.5	144.8	147.9	150.0	151.9	153.9	156.1	158.5	162.0	164.6	167.3	170.0	172.9	175.7	
D-2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
A-1	57.7	58.4	59.2	60.1	61.5	62.8	63.0	63.3	63.6	64.0	64.5	64.9	65.4	65.8	66.3	66.8	
A-2	114.8	115.8	117.0	118.2	120.1	122.0	122.4	122.8	123.3	123.8	124.5	125.1	125.8	126.4	127.1	127.7	
A-3	33.3	33.5	33.9	34.3	34.8	35.4	35.5	35.6	35.8	35.9	36.2	36.3	36.5	36.7	36.9	37.1	
OL	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
M-1	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	
M-2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	
M-3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
CT	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	
Sales	**361.4**	**364.9**	**369.1**	**374.0**	**380.8**	**386.7**	**389.3**	**392.2**	**395.3**	**398.6**	**403.7**	**407.5**	**411.4**	**415.5**	**419.7**	**423.9**	**1.11%**
Check																	
Losses	**11.4**	**11.5**	**11.6**	**11.8**	**12.0**	**12.2**	**12.2**	**12.3**	**12.4**	**12.5**	**12.7**	**12.8**	**12.9**	**13.1**	**13.2**	**13.3**	

Monthly Peak Demand Forecast (Megawatts):

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	
Jul	46.87	47.61	48.29	49.19	50.24	51.35	51.95	52.61	53.40	54.24	55.52	56.42	57.33	58.26	59.19	60.10	
Aug	54.48	55.06	55.66	56.44	57.48	58.26	58.70	59.17	59.72	60.43	61.52	62.29	63.07	63.87	64.68	65.47	
Sep	64.89	65.55	66.08	67.04	68.24	69.02	69.30	69.73	70.20	70.72	71.47	72.20	73.04	74.06	75.15	76.25	
Oct	57.20	57.45	57.96	58.54	59.45	60.27	60.53	60.81	61.12	61.46	62.00	62.38	62.78	63.19	63.63	64.05	
Nov	53.63	54.22	54.86	55.80	56.99	57.85	58.37	58.92	59.51	60.12	61.08	61.76	62.57	63.58	64.59	65.58	
Dec	62.57	63.39	64.18	65.21	66.51	67.42	67.98	68.57	69.20	69.86	70.88	71.62	72.37	73.15	74.24	75.33	
Jan	57.60	58.28	59.24	60.42	61.58	62.82	63.36	63.93	64.53	65.16	66.44	67.40	68.39	69.38	70.40	71.39	
Feb	58.20	58.95	60.00	61.29	62.66	63.90	64.45	65.02	65.63	66.27	67.24	67.95	68.67	69.42	70.19	70.93	
Mar	54.91	55.57	56.41	57.46	58.61	59.63	60.08	60.63	61.33	62.06	63.18	63.98	64.80	65.63	66.49	67.33	
Apr	50.49	51.02	51.57	52.30	53.58	54.02	54.30	54.62	55.09	55.66	56.54	57.20	57.90	58.77	59.65	60.52	
May	47.16	48.13	49.20	50.49	52.06	53.20	54.08	55.00	55.96	56.96	58.48	59.55	60.64	61.73	62.84	63.92	
Jun	50.70	51.28	52.19	53.26	54.43	55.52	55.91	56.33	56.77	57.24	57.94	58.46	58.99	59.53	60.09	60.64	
FYear	**64.89**	**65.55**	**66.08**	**67.04**	**68.24**	**69.02**	**69.30**	**69.73**	**70.20**	**70.72**	**71.47**	**72.20**	**73.04**	**74.06**	**75.15**	**76.25**	**0.97%**
Check																	
Growth		**1.01%**	**0.81%**	**1.45%**	**1.80%**	**1.13%**	**0.42%**	**0.62%**	**0.68%**	**0.74%**	**1.05%**	**1.02%**	**1.18%**	**1.40%**	**1.46%**	**1.46%**	

Fiscal Year 2027 Load Forecast

January 12, 2026

Overview

Background

Fiscal Year 2027 Load Forecast

Comparison with Prior Years

Next Steps

BACKGROUND

Rationale for a Load Forecast

Short-Term

AMP's Power budget

AMP's Pro forma

Cost-of-service & Ratemaking

Short-term revenue projections

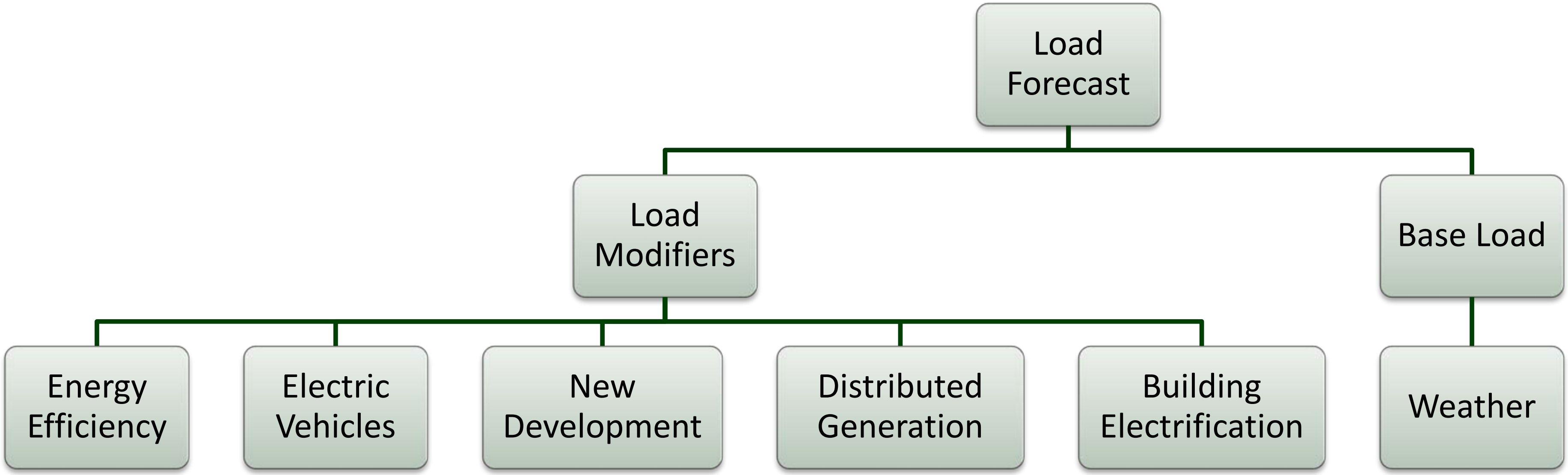
Long-Term

Resource planning

Long-term compliance

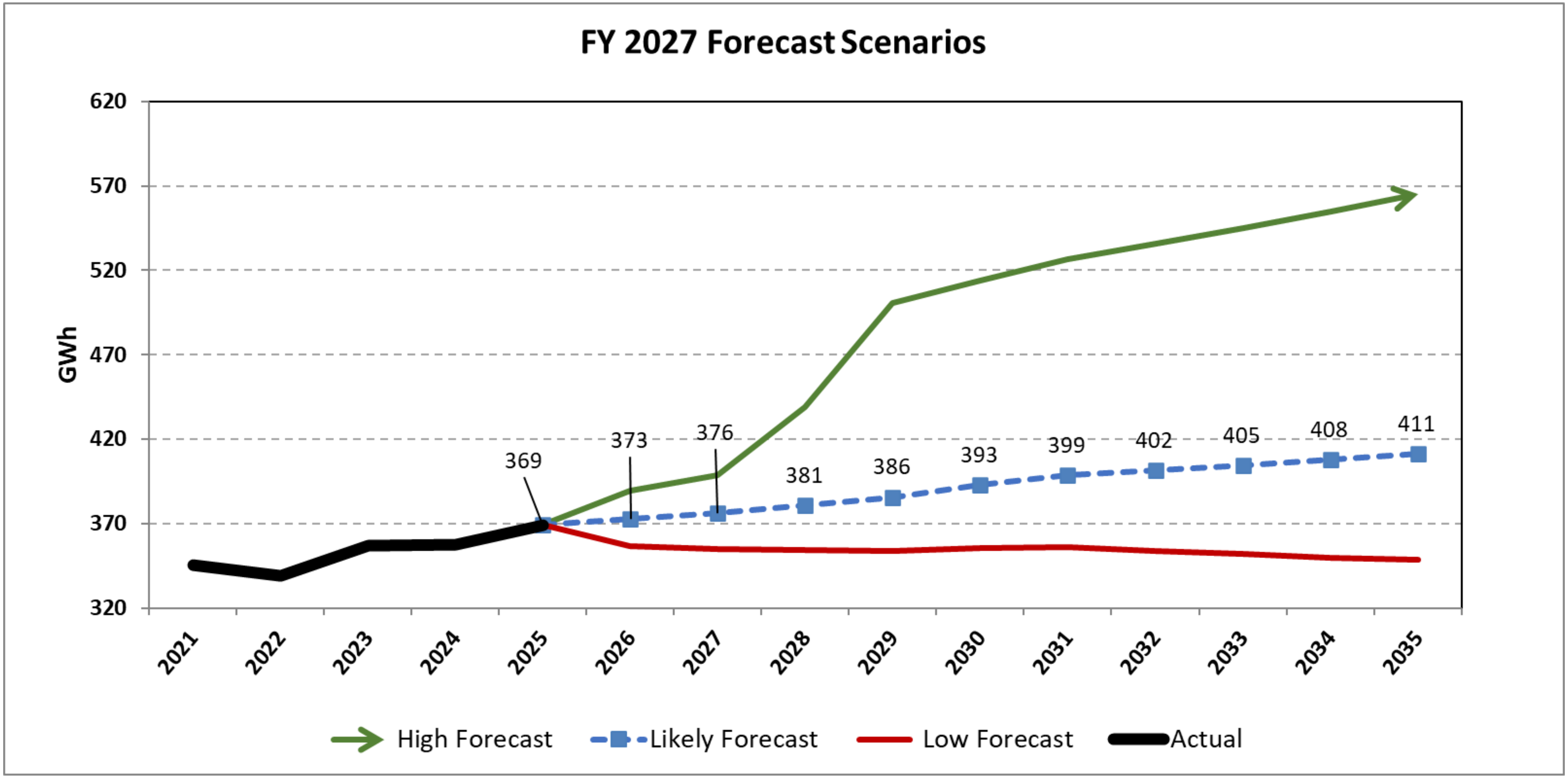
Financial planning

Forecast Methodology

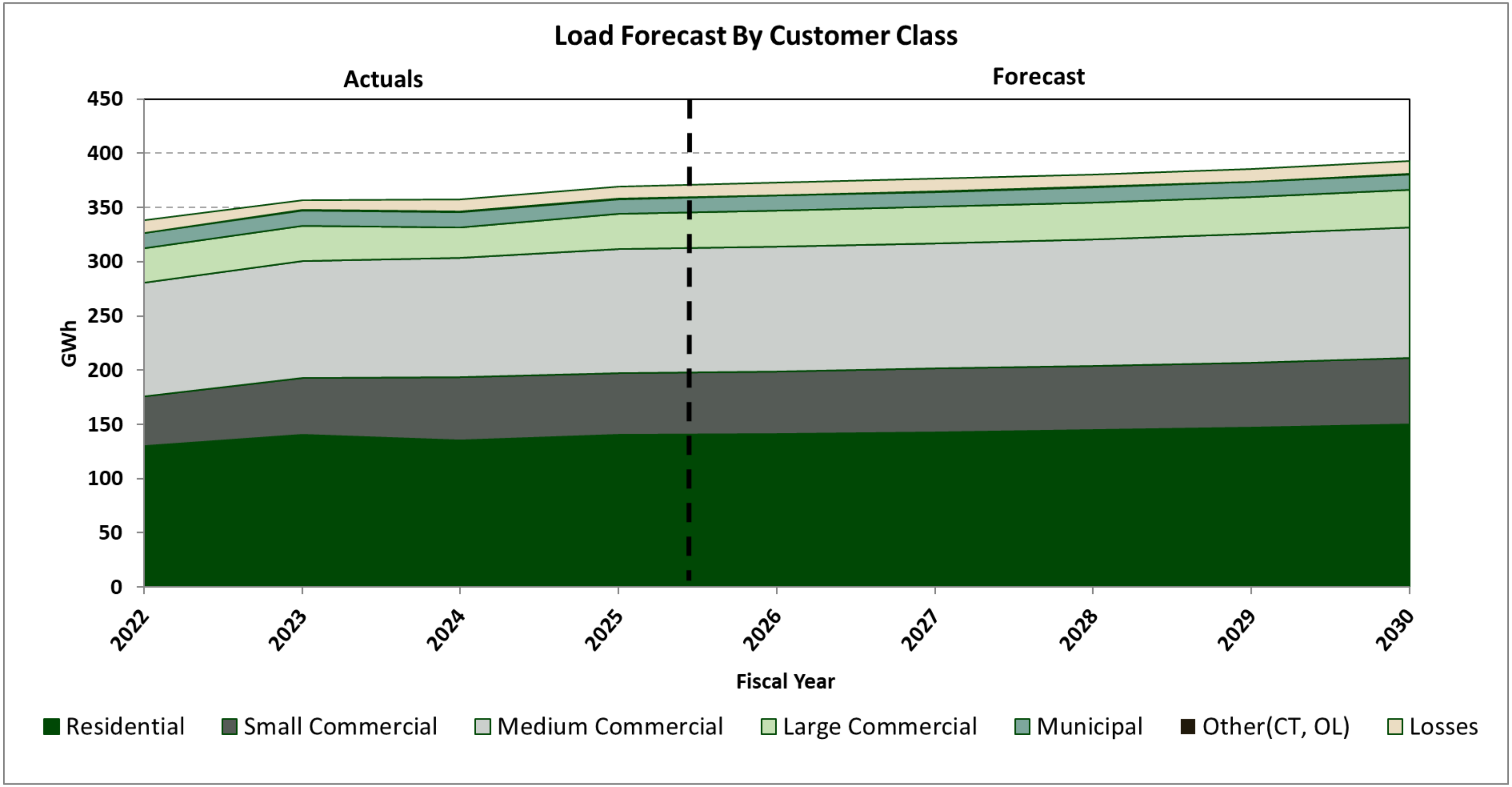


RESULTS

Load Forecast



Customer Class Breakdown



ALAMEDA MUNICIPAL POWER
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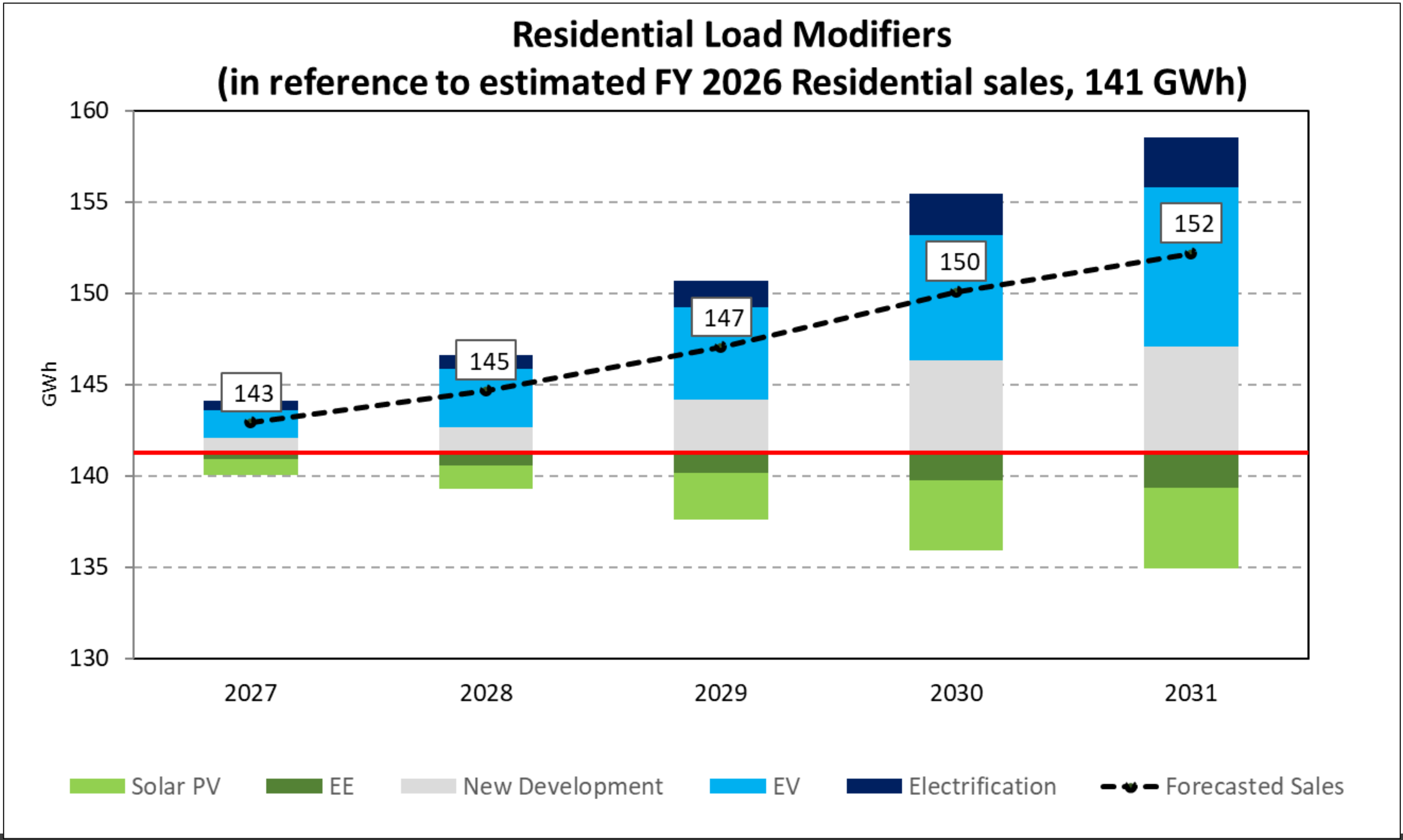
Residential Sales Forecast

Five-Year Residential Sales: Most Likely Scenario



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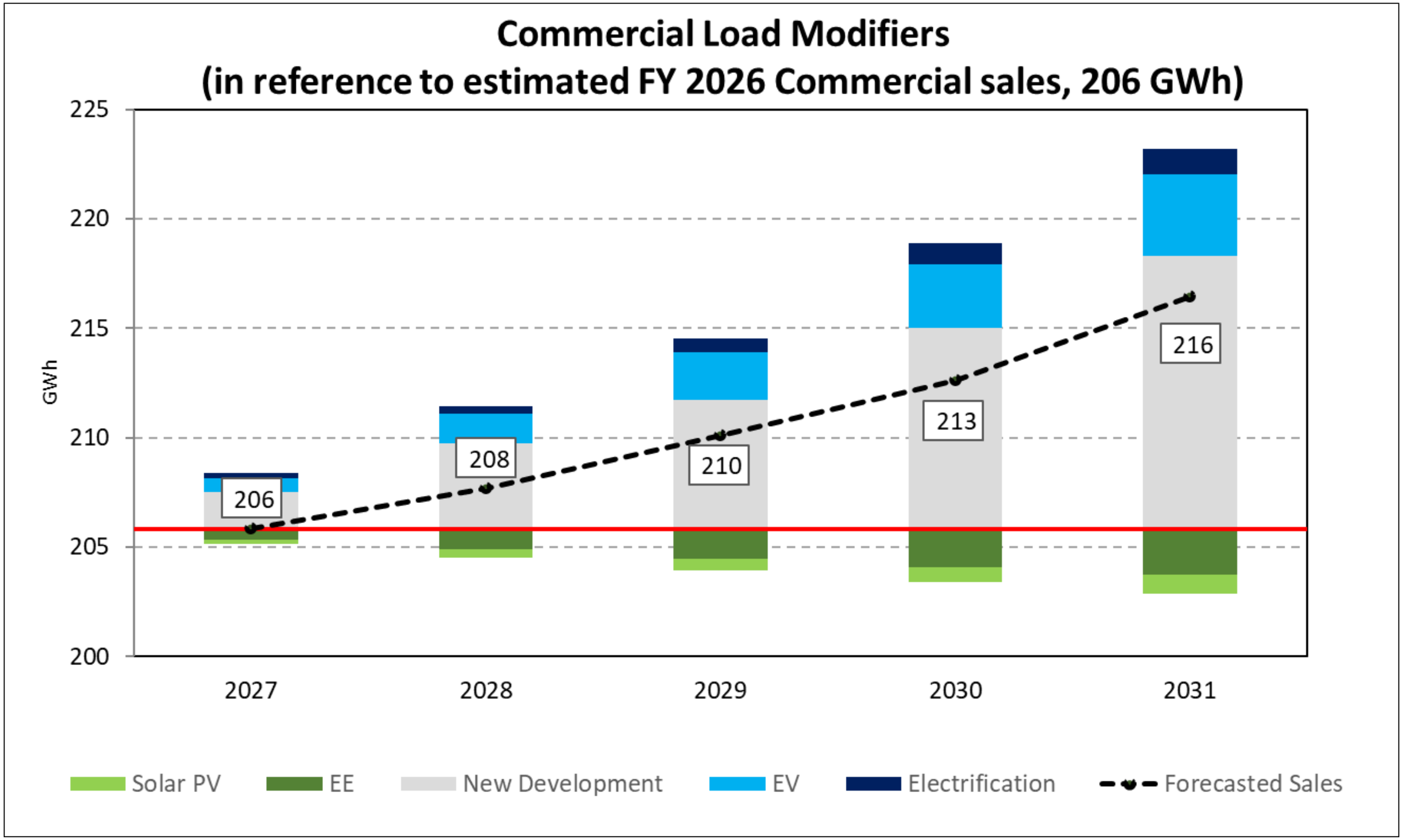
Commercial Sales Forecast

Five-Year Commercial Sales: Most Likely Scenario



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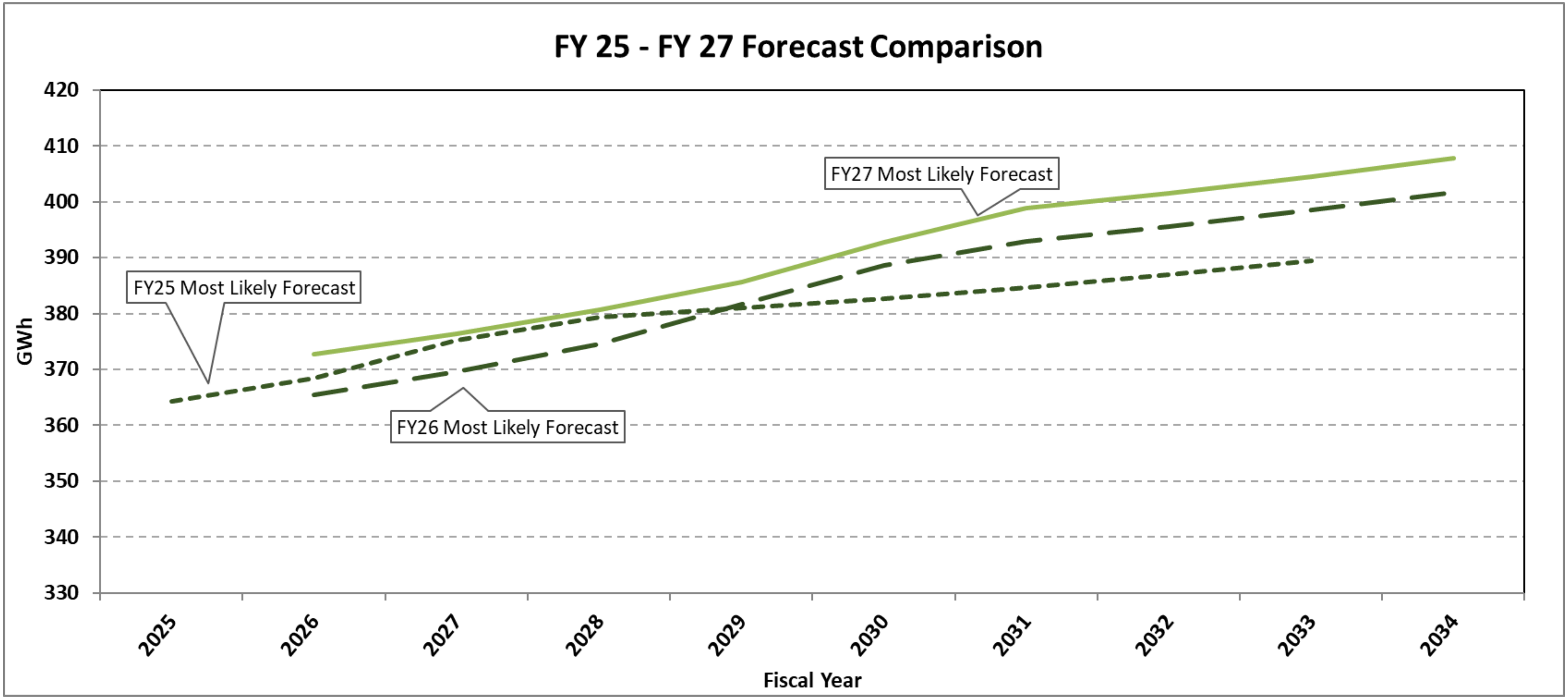
COMPARISON TO PRIOR YEARS

Load Forecast Comparison to Prior Years



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Forecast Error: Prior Year Forecasts

- Forecast Load v. Actual Load
  - FY 2022 larger margin, related to Covid-19

Fiscal Year	Forecast Load (GWh)	Actual Load (GWh)	% Difference
2022	354	338	-4.34%
2023	348	357	2.37%
2024	351	358	1.86%
2025	364	369	1.37%
2026 (YTD)	366 (185)	(188)	1.61%
2027	376	-	-

Key Takeaways

- The FY 2027 forecast remains similar to the prior year's forecast but with a higher starting point following recent actuals.
- Year-over-year growth averages 1 percent over the 10-year forecast window.

Next Steps

- Staff recommends accepting Alameda Municipal Power's FY 2027 Load Forecast
- Staff will use the Load Forecast for:
  - Pro forma, 10-Year: March 16
  - FY 2027 Budget/Rates: April 20
  - Northern California Power Agency (NCPA) Monthly Pre-billing for FY 2027

Questions?

Alan Harbottle
harbottle@alamedamp.com
Ph: 510-814-6403

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

AGENDA ITEM NO.: 5.B.1
MEETING DATE: 01/12/2026
ADMINISTRATIVE REPORT NO.: 2026-43
ACTION: BY MOTION

To: Honorable Public Utilities Board

Submitted by: /S/
Alan Harbottle
Acting AGM – Engineering & Operations

From: Sameh Seleman, P.E.
Engineering Manager

Tito R. Nagrampa Jr., P.E.
Senior Electrical Engineer

Approved by: /S/
Tim Haines
General Manager

Subject: By Motion, Authorize the General Manager to Transfer Funds Within the Capital Improvement Budget and Execute a Transmission Facilities Agreement with Pacific Gas and Electric Company for the Line Current Differential Relaying Transmission Protection Project Between Jenney Substation and Oakland Station J in an Amount Not to Exceed $ 7,511,477, with a Contingency of $308,523, For a Total Amount Not to Exceed $7,820,000 and Find the Action Exempt from the California Environmental Quality Act

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RECOMMENDATION

By motion, find AMP's action is not a CEQA project pursuant to CEQA Guidelines Section 15378, is exempt from the California Environmental Quality Act pursuant to CEQA Guidelines Sections 15061(b)(3) and 15378 for the reasons outlined in the administrative report, and authorize the General Manager to transfer funds within the capital improvement budget and to execute a transmission facilities agreement with Pacific Gas and Electric Company for the line current differential relaying transmission protection project between Jenney substation and Oakland Station J in an amount not to exceed $7,511,477, with a contingency of $308,523, for a total amount not to exceed $7,820,000.

BACKGROUND

Alameda Municipal Power (AMP) utilizes line current differential relaying protection for 115 kilovolt (kV) transmission lines using either copper or fiber optic communication channels for high-speed transmission line protection. This protection scheme is critically important in protecting the transmission line assets, especially for the submersible cable that crosses under the Oakland-Alameda estuary towards Pacific Gas and Electric Company (PG&E) Stations C and J in Oakland.

AMP's existing line current differential protection schemes using fiber optic channel communication are between AMP's Jenney and Cartwright substations, Cartwright and the Northern California Power Agency (NCPA) Combustion Turbine (CT) substations, and NCPA-CT and PG&E Station C. The existing copper communication channel is between Jenney substation and PG&E Station J, which is no longer in service.

The leased copper wire from AT&T used for the pilot wire communication channel of the line current differential relaying between Jenney and Station J became unavailable about 15 years ago. The GE electromechanical relay that was used in conjunction with the line current differential relaying is obsolete, prone to misoperation, and no longer supported by the manufacturer. In the interim, AMP and PG&E have replaced the transmission line protection relays between Jenney and Station J with microprocessor-based Schweitzer Engineering Laboratories (SEL) distance and overcurrent relays, which are slower and less reliable than line current differential relay protection. Distance and overcurrent relays are typically applicable for back-up line protection only.

The Public Utilities Board approved $7 million dollars for the capital project as part of the June 2025 Budget approval. The Board asked why the project was being carried out now, given the current protection scheme has been in place for many years and has not resulted in a major failure. AMP staff responded that the current arrangement relies on a backup protection scheme that was never intended to be permanent and does not meet today's standards for protecting critical, hard-to-replace infrastructure and reliable service standards.

DISCUSSION

The absence of high-speed transmission protection between Jenney and Station J will have ongoing reliability, and possibly financial, impacts on AMP such as

1. Damage to AMP 115 kV submarine cables between East Transition Station to Tidewater Terminating Station during line faults. The cost of replacing damaged cables is estimated between $10–20 million but could be higher due to permitting requirements. During the replacement, AMP would have to operate in single source for at least three to six months, thereby exposing system reliability.

2. According to PG&E, distance relays installed at Station J were set to overreach Zone 1 to protect AMP submersible cables that crossed the Oakland-Alameda estuary. The relay may trip the breaker even if the fault is outside of its zone of protection. A high fault on AMP's 115 kV bus and 12 kV system at Jenney may cause PG&E's distance relay to operate, tripping the breaker feeding Jenney, and leaving thousands of AMP customers without power.

Distance relaying is not very reliable. Any of the conditions below may cause relay-breaker misoperation:

1. Infeed
2. Fault resistance
3. Unequal measure impedances during fault
4. Evolving fault
5. Power swings
6. Short lines
7. Simultaneous faults

AMP and PG&E engineers have agreed to a high-speed line current differential protection between Jenney and Station J to mitigate potential problems in the transmission line in the event of line faults. Staff explored various means to restore the line current differential protection scheme, including installing or leasing direct path fiber optic line from AT&T.

However, the absence of underground infrastructure and high costs of crossing the Oakland-Alameda estuary and Interstate-880 make this a non-viable option.

In 2019, AMP staff approached PG&E regarding alternative options to have the line current differential current protection implemented. PG&E engineers have offered to utilize their existing fiber optic communication lines infrastructure between Station C and Station J for this project. AMP staff has carefully studied feasibility and initiated the project with PG&E. AMP has an existing fiber optic infrastructure from Jenney through Oakland Station C, making this project more viable and less expensive.

Project Justification
Staff recommends approval of a transmission facilities agreement (TFA) with PG&E for the line current differential project for the following reasons:

1. This project will provide a higher level of system reliability, protection, and control of the 115 kV transmission lines between Jenney and Station J.

2. Using the PG&E fiber optic communication channel is more economical than installing new direct fiber infrastructures crossing the Oakland-Alameda estuary and Interstate-880.

NEXT STEPS

If approved, AMP will pay PG&E the construction estimate upfront and the one-time cost of ownership charge once facilities are complete as stipulated in the TFA. AMP staff will collaborate with PG&E engineers during the design, construction, and commissioning of the new line current differential transmission protection between the two substations.

FINANCIAL IMPACT

AMP has allocated $7 million in the Capital Improvement fund for this important project in fiscal year (FY) 2026. This project will require an additional $820,000 for PG&E project costs, a one-time charge for Cost of Ownership, and contingencies.

AMP’s Budget Policy requires Public Utilities Board approval for transfers greater than $100,000. Staff recommend authorizing the General Manager to transfer two capital improvement budget funds amounting to $468,000 and $ 352,000 intended for “10 MW Load (Pacific Fusion)” and “WETA Harbor Bay Charging Ferry Terminal”, respectively. Pacific Fusion has selected New Mexico as the site of their new laboratory facilities and the Water Emergency Transportation Authority (WETA) Harbor Bay Charging Ferry Terminal is projected to start construction in 2027 and be completed in 2028.

AMP expects approximately $300,000 in additional costs needed to complete the project including consulting, capitalized labor, and SEL equipment purchases. AMP will budget for these amounts in FY 2027.

ENVIRONMENTAL IMPACT

Alameda Municipal Power finds the transmission facilities agreement with PG&E is not a project as defined by CEQA Guidelines Section 15378, which excludes "Continuing administrative or maintenance activities, such as purchases for supplies." AMP's action involves entering into an agreement for the protection of the line current differential relaying transmission between Jenney Substation and Oakland Station J. Alameda Municipal Power further finds that it can be seen with certainty that there is no possibility that the activity will result in a direct or reasonably foreseeable indirect change in the environment.

Alameda Municipal Power further finds that its actions are exempt from CEQA, including but not limited to CEQA Guidelines Section 15061(b)(3). More specifically, Alameda Municipal Power finds its actions are subject to the commonsense exemption because it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment. Alameda Municipal Power's actions involve entering into an agreement for the protection of the line current differential relaying transmission between Jenney Substation and Oakland Station J.

LINK TO STRATEGIC PLAN AND METRICS

Business Resiliency: Strategy 1, AMP will develop an asset management plan to guide efficient capital and maintenance expenditures which improve system operations and resiliency.

EXHIBIT

A. Transmission Facilities Agreement
B. PG&E Scope of Work

TRANSMISSION FACILITIES AGREEMENT FOR ALAMEDA MUNICIPAL POWER

OAKLAND J-ALAMEDA 115 KV LINE PROTECTION UPGRADE WORK

At the request of **Alameda Municipal Power** (**"AMP"** or **"Customer") Pacific Gas and Electric Company** (**"PG&E"**), a California corporation (collectively, "**Parties**") agrees to furnish at AMP's expense, certain Facilities and perform certain work described in Exhibit A-1 ("Special Facilities"). The Facilities are furnished to serve AMP's electric service requirements at PG&E Oakland J Substation and PG&E Oakland C Substation located at Oakland, State of California, as described in that Exhibit. This Transmission Facilities Agreement ("TFA"), inclusive of its Exhibits, is entered into pursuant to the Interconnection Agreement Between Pacific Gas and Electric Company and the Northern California Power Agency ("NCPA"), Service Agreement No. 292 under PG&E's FERC Electric Tariff Volume No. 5 ("NCPA IA") and is subject to all terms and conditions thereof. For purposes of this Agreement, if any term or condition of this Agreement conflicts with the NCPA IA, this TFA shall govern.

1. This TFA includes:

Exhibit A, Detail of Special Facilities Charges. Exhibit A may be revised or superseded by written agreement of the Parties and without formal amendment of the remainder of this TFA.

2. Definition of Special Facilities:

Special Facilities are those Facilities described in Exhibit A required to meet the Customers application for the interconnection of Customer's project with PG&E's electric system. The Special Facilities charges in Exhibit A shall apply only to the project elements which are in addition to or in substitution for the standard facilities which PG&E normally provides for transmission interconnection. Charges related to future maintenance and operations of such Special Facilities will apply.

3. AMP shall pay PG&E pursuant to the payment schedule set forth in Exhibit A, Section II, a charge equal to the sum of the amounts which are specified [subject to true-up as provided in Sec. 4 of this agreement] in Exhibit A [currently estimated at $4,017,810.06]. Under

this Agreement, AMP shall pay PG&E $4,017,810.06 ("Payment") for the 2025-2026 Fiscal Year of the Project following the execution and the filing of this Agreement with FERC.

4. PG&E will attempt to notify Customer at least 30 calendar days prior to the anticipated date that Customer's Payment (and any future payments) is exhausted based upon the aggregated costs of PG&E's work or as soon thereafter as is reasonably feasible. With such notice, PG&E shall provide Customer with an accounting of work performed against funds from Customer's Payment expended, along with an updated estimate of the additional funds necessary to complete the work. Within 15 calendar days of receiving such a notice, Customer shall send PG&E the additional amount that PG&E estimates will be required to complete the work ("Supplemental Payment"). If the Supplemental Payment is not received within the 15 calendar days of PG&E's notice, PG&E may, at its option, elect to halt work activities under this Agreement until this payment is received. If PG&E elects to continue providing the work without having received such Supplemental Payment, Customer remains responsible for payment for the costs of the work rendered by PG&E, including any cost overruns that exceed the initial $4,017,810.06 estimate. Once PG&E completes the Work, PG&E will provide Customer with an accounting of work performed against Customer's Payment(s) received, and will refund any outstanding balance (if funds provided by Customer are left unused) or invoice Customer (if PG&E has drawn on all funds previously provided by Customer and the costs of the work rendered exceeded the total amount of funds) within 60 calendar days of completion of the Work. Customer shall pay such invoice within 30 calendar days of receipt of such invoice.

5. Where AMP has requested Special Facilities, AMP also shall pay PG&E any applicable monthly rates and charges plus an ownership charge, under either (a) or (b) below as specified in Exhibit A:

(a) A Cost-of-Ownership Charge representing PG&E's continuing monthly cost of financing (if PG&E has financed the facilities), owning, operating, and maintaining Special Facilities; or

(b) An Equivalent One-Time Charge equal to the present value of the monthly Cost-of-Ownership Charge in perpetuity.

The Cost-of-Ownership Charge shall commence on the date Special Facilities are first available for AMP's use as such date is established in PG&E's records. PG&E will notify AMP, in writing of such commencement date. The Equivalent One-Time Charge (if applicable) shall be payable by AMP to PG&E on demand.

6. The Cost-of-Ownership Charge for interconnections provided under this TFA is determined by PG&E in accordance with PG&E's applicable percentage rates, which are calculated using PG&E's most recent transmission owner revenue requirement on file with and accepted by the FERC. PG&E charges the following Cost-of-Ownership rates for transmission facilities: customer-financed, transmission-level rate = 0.61% monthly.

7. Where it is necessary to install Facilities on AMP's premises, AMP hereby grants to PG&E:

(a) the right to make such installation on AMP's premises along the shortest practical route thereon with sufficient legal clearance from all structures above and below ground now or hereafter erected or installed on AMP's premises; and

(b) the right of ingress and egress from AMP's premises at all reasonable hours for any purposes reasonably connected with the installation operation and maintenance of Facilities.

8. When formal rights of way or easements are required on or over property of AMP's or the property of third parties for the installation of Facilities, AMP agrees that PG&E shall use all reasonable efforts to obtain such rights of way or easements, which shall be at AMP's expense or, if AMP and PG&E agree, AMP shall obtain any necessary permanent rights of way or easements, satisfactory to and without cost to PG&E.

9. To the extent that modification is required of other agreements between AMP and PG&E regarding current or planned transmission projects in the vicinity of or impacted by the Facilities to be installed in connection with this TFA, AMP and PG&E shall make good faith efforts to agree on such modifications, recognizing that such modifications may be a necessary element of the overall scheme of generation and transmission facilities sought to be installed by

PG&E and also recognizing that PG&E has already expended effort and costs to fulfill such other agreements.

10. PG&E shall not be responsible for any reasonable delay in completion of the installation of Facilities resulting from shortage of labor or materials, strike, labor disturbance, war, riot, weather conditions, governmental rule, regulation or order, including orders or judgments of any court or regulatory agency, delay in obtaining necessary rights of way and easements, acts of God, delays resulting from PG&E's responsibility to coordinate certain electric interconnections or modifications with the California Independent System Operator Corporation, or any other cause or condition beyond the control of PG&E, nor shall PG&E be liable for direct, incidental, indirect, special, punitive, or consequential damages for such delay. PG&E shall have the right, if for one of the above reasons it is unable to obtain materials or labor for all of its construction requirements, to allocate materials and labor to construction projects which it deems, in its sole discretion, most important to serve the needs of its customers, and any delay in construction, hereunder resulting from such allocation shall be deemed to be a cause beyond PG&E's control.

11. New electric extensions and connections, capacity upgrades to existing facilities, conduits and substructures, and the maintenance of facilities, conduits and substructures provided under this TFA shall be installed and made in accordance with fundamental design, installation, ownership, and maintenance provisions of Applicable Requirements and Good Utility Practice as defined in Section 7, Interconnections, of the NCPA IA, and Interconnection facilities for Points of Interconnection at transmission voltage shall be installed and maintained in accordance with PG&E's Transmission Interconnection Handbook. All charges, payments and refunds shall be made solely under the provisions of this TFA.

12. Charges paid by AMP:

If PG&E is prevented from completing the installation of Facilities for reasons beyond its reasonable control after twelve (12) months following the date of this TFA, PG&E shall have the right to supersede the applicable Exhibit or Exhibits to this TFA upon at least thirty (30) days' written notice to AMP. PG&E shall have the right to adjust any amounts paid or required to be paid by AMP hereunder that may be due based on that portion of the Facilities then completed, if any, utilizing the estimated costs developed by PG&E for the applicable Exhibit or Exhibits to this TFA. Such superseding Exhibit or Exhibits shall be in substantially the same form as the applicable Exhibit or Exhibits to this TFA and be approved in writing by the Parties hereto. If AMP does not approve the superseding Exhibit or Exhibits within thirty (30) days of PG&E's notice, the applicable Exhibit or Exhibits to this TFA shall terminate, and the provisions of Section 14 herein shall be applied to that portion of Facilities then completed. AMP also shall reimburse PG&E for any actual documented expenses it may have incurred for engineering, surveying, right of way acquisition and other work associated with that portion of Facilities not installed.

13. This TFA shall become effective when it is executed by the Parties hereto. Except as provided for in Section 12 herein, this TFA shall remain in force until one of the following events occurs:

(a) The NCPA IA or its successor, terminates without a successor, or

(b) AMP fails to pay the monthly Cost-of-Ownership Charge prescribed in the applicable Exhibit to this TFA, if applicable; or

(c) The Parties agree in writing to terminate this TFA.

Either Party shall provide the other Party at least thirty (30) days' written notice of termination pursuant to subpart (b) and an opportunity to cure before termination becomes effective pursuant to this Section 13.

14. Upon termination of the TFA for any reason:

(a) AMP shall pay to PG&E a Facilities Termination Charge, defined as the estimated Installed cost, plus the estimated removal cost less the estimated salvage value for any Facilities which can be removed, all as determined by PG&E in accordance with its standard accounting practices. PG&E shall deduct Total Cost as set forth in Exhibit A, Section 3, line E (the “Initial Charge”) from the Facilities Termination Charge. Any remaining balance of the Equivalent One-Time Charge previously paid, if any, will be refunded by PG&E to AMP, and any deductions in the Equivalent One-Time Charge shall be calculated using the number of months that the TFA was in force and effect, multiplied by the monthly charge of the Net Cost of Special Facilities set forth the table in Section 4 of Exhibit A. If the Initial Charge paid is greater than the Facility Termination Charge, PG&E shall refund the difference, without interest to AMP within a reasonable time; and

(b) PG&E shall be entitled to remove and shall have a reasonable time in which to remove any portion of the Facilities located on AMP's premises.

(c) Pursuant to FERC's rules and regulations, PG&E will make a filing and obtain FERC acceptance prior to billing AMP for any Facility Termination Charge.

15. Special Facilities shall be owned by PG&E unless otherwise agreed in writing by the Parties.

16. Mobile-Sierra. Notwithstanding any provision of this Agreement, neither Party shall seek, nor shall they support any third party in seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this Agreement through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of this Agreement proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

17. No transfer or assignment of either Party's rights, benefits or duties under this TFA shall be effective without the prior written consent of the other Party, which consent shall not be withheld unreasonably; provided, however, that this Section 17 shall not apply to interests that arise by reason of any deed of trust, mortgage, indenture or security agreement granted or executed by either Party. No partial assignment of either Party's rights, benefits or duties shall be permitted under this TFA unless otherwise agreed to by the Parties. Any successor to or transferee or assignee of the rights or obligations of a Party, whether by voluntary transfer,

judicial sale, foreclosure sale or otherwise, shall be subject to all terms and conditions of this TFA to the same extent as though such successor, transferee, or assignee were an original party.

18. Any dispute arising from this TFA shall be resolved in accordance with Appendix B of the NCPA IA.

19. AMP's liability for the ITCC taxes under this Letter Agreement shall equal the product of (i) the gross income realized by PG&E for income tax purposes with respect to the payments or property transfers made by AMP to PG&E under this Agreement for the construction of Special Facilities multiplied by (ii) the "Gross-up Percentage" (as defined below). The "Gross-up Percentage" shall equal the gross-up percentage determined in accordance with "method 5," as described in CPUC Decision 87-09-026 for taxable contributions-in-aid-of-construction paid to PG&E in the year the Gross Income Amount is includable in PG&E's taxable income. The "Gross-up Percentage" shall be presumed to be the percentage set forth in PG&E's electric tariffs accepted by the CPUC for taxable contributions in aid of construction.

20. This TFA may be executed in any number of counterparts, each of which shall be an original and all of which together shall constitute one instrument.

21. This TFA may be amended or modified only by the written agreement of the Parties, except as otherwise specifically provided herein.

22. This TFA, inclusive of its exhibits and, by reference, the NCPA IA, constitutes the complete and final expression of the rights and obligations of the Parties in connection with the subject matter of this TFA and is intended as a complete and exclusive statement of the terms of their agreement which supersedes all prior and contemporaneous offers, promises, representations, negotiations, discussions, communications, and contracts which may have been made in connection with the subject matter of this TFA. The exhibits to this TFA, as they may be revised from time to time, are attached to this TFA and are incorporated by reference as if herein fully set forth.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by authorized representatives this ___ day of ________ 2026 but effective as set forth above.

ALAMEDA MUNICIPAL POWER

By: ______________________________

Printed Name: Timothy Haines

Title: General Manager

Date: ______________________________

Approved as to form:

By: Signed by: Lonnie Eldridge E47E2847130B4D6...

Printed Name: Lonnie Eldridge

Title: Special Counsel, City of Alameda

Date: 12/30/2025

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________________

Printed Name: ______________________________

Title: ______________________________

Date: ______________________________

Attachments

Exhibit A

Exhibit A

Detail of Special Facilities Charges
<u>Oakland J-Alameda 115 kV Line Protection Upgrade Work</u>

At the request of the ALAMEDA MUNICIPAL POWER ("AMP"), PACIFIC GAS AND ELECTRIC COMPANY ("PG&E") hereby agrees to furnish at AMP's expense certain Special Facilities necessary to serve AMP's electric service requirements at PG&E's Oakland C 115 kV Substation, located at Oakland, State of California. The Special Facilities are described in Exhibit A-1.

1. **<u>Scope and Cost Estimate</u>**

The location and requested Work are described as follows:

Locations: PG&E Oakland J Substation and PG&E Oakland C Substation

Description of Work:

AMP has requested PG&E to 1) upgrade the existing Oakland J-Alameda 115kV line protective relaying at PG&E Oakland J Substation CB 122, and 2) provide a fiber communication path between the PG&E Oakland C Substation and the PG&E Oakland J Substation for the line current differential relay communication. The purpose of this work is to provide high speed protection for Oakland J-Alameda 115kV line. Prior to the beginning of this Project, AMP has already established a fiber communication path between Jenney Substation and Oakland C Substation.

PG&E will perform the necessary procedures to ensure that the installation and activation of two SEL-411L line current differential relays at Oakland J Substation, and the establishing of a fiber communication path between Oakland C Substation and Oakland J Substation, comply with PG&E's Interconnection Handbook. Procedures will include, but not be limited to, the following tasks: PG&E's identification and assignment of a project team, project kick-off, schedule walk-down, preliminary engineering scoping, project walk-down, identification of clearance requirements, environmental review, permitting, and final development and approval of scope documentation.

Similarly, AMP will perform the necessary procedures to ensure that the installation and activation of two SEL-411L line current differential relays at Jenney Substation, and the establishing of a fiber communication path between Jenny Substation and Oakland C Substation, are in compliance with PG&E's Interconnection Handbook. Procedures will include, but not be limited to, the following tasks: AMP's identification and assignment of a project team, project kick-off, schedule walk-down, preliminary engineering scoping, project walk-down, identification of clearance requirements, environmental review, permitting, and final development and approval of scope documentation.

2. Estimated Costs of 115 kV Relay Upgrade Project

Line Item	Unit Cost	Quantity	Total Cost
Labor	$85.00	7,250	$616,250.00
Materials	$175,000.00	1	$175,000.00
Overheads	$1,701,188.00	1	$1,701,188.00
Estimated Total Cost			= $2,492,438.00
Contingency		30%	$747,731.40
Total w/Contingency, Before ITCC			**= $3,240,169.40**
ITCC (Applicable Federal Income Tax Rate)		24%	$777,640.66
TOTAL ESTIMATE			**$4,017,810.06**

3. Cost Estimate and Payment Schedule

A	Net Cost of PG&E Facilities	$3,240,169.40
	ITCC (24%)	$777,640.66
	Total Cost of PG&E Facilities (including ITCC, see Exhibit A-1)	= $4,017,810.06
B	Less the cost of "removable and reusable" facilities which are provided, installed, financed, and furnished by PG&E	$0.00
C	Less PG&E's estimate of the total cost of facilities provided and installed by Customer (excluding costs of design and administration by PG&E)	$0.00
D	Payment at contract execution with FERC approval	$4,017,810.06
	Total Payment	**$4,017,810.06**
E	**Total Cost**	**$4,017,810.06**

4. Estimated Monthly Cost-of-Ownership Charge

Special Facilities Financed By	Application Base	Current Percentage Rate	Monthly Charge
AMP	Net Cost of Special Facilities (= A-1 Direct Assignment Facilities below) 1. Estimated cost of transmission facilities installed by PG&E: <u>$3,240,169.40</u> 2. Estimated cost of transmission facilities installed by AMP and deeded to PG&E: <u>$0</u> Less allowance for existing facilities: -- Estimated net amount: <u>$3,240,169.40</u>	0.61%	$19,765.03/month
PG&E	Existing facilities allocated as Special Facilities	-	-
Total Estimated Monthly Cost-of-Ownership Charge			**$19,765.03/month**

5. **Estimated <u>Equivalent of One Time Charge</u>** (in lieu of estimated monthly Cost-of-Ownership Charge)

☒ **Check here if applicable**

$19,765.03/mo. (IV.C above) x 12 months × 14.73 (present worth factor) =

$ 3,493,666.70

VI. Liability and Indemnity

Section 25 of the NCPA IA, Indemnity, and Section 27 of the NCPA IA, Liability, shall apply to this TFA.

In no event shall either Party hereto or any subcontractor be liable for indirect, special, incidental, consequential or exemplary damages, including but not limited to, the loss of profits or revenue, loss of use of the equipment or any associated equipment, cost of capital, cost of substitute equipment, facilities or services, down time costs, casts in excess of estimates, loss of opportunity, loss of data, loss of goodwill or claims of customers of the other Party for such damages, and each Party hereby releases each other Party there from.

Interconnection Agreement

Between

Pacific Gas and Electric Company

and

Northern California Power Agency

and

City of Alameda,

City of Biggs,

City of Gridley,

City of Healdsburg,

City of Lodi,

City of Lompoc,

City of Palo Alto,

City of Ukiah,

and

Plumas-Sierra Rural Electric Cooperative

Service Agreement No. 292 under

PG&E FERC Electric Tariff Volume No. 5

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INTERCONNECTION AGREEMENT
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY
AND
NORTHERN CALIFORNIA POWER AGENCY
AND
CITY OF ALAMEDA,
CITY OF BIGGS,
CITY OF GRIDLEY,
CITY OF HEALDSBURG,
CITY OF LODI,
CITY OF LOMPOC,
CITY OF PALO ALTO,
CITY OF UKIAH,
AND
PLUMAS-SIERRA RURAL ELECTRIC COOPERATIVE

1 PREAMBLE

This Interconnection Agreement (Agreement) is made this 28th day of September, 2015 by and between Pacific Gas and Electric Company (PG&E), a corporation organized and existing under the laws of the State of California, and the Northern California Power Agency (NCPA), a joint powers agency of the State of California, and the California Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Ukiah, and the Plumas-Sierra Rural Electric Cooperative, Inc., (hereinafter referred to collectively as "NCPA Member Customers"), any or all of which are hereinafter referred to individually as a "Party" and collectively as "the Parties." NCPA and the NCPA Member Customers are hereinafter referred to collectively as "the NCPA Parties."

2 RECITALS

2.1 Whereas, it is the policy of the Federal Energy Regulatory Commission (FERC) that open and non-discriminatory access to transmission be provided through transmission systems comprising as large an area as possible under the supervision and direction of an independent system operator or a regional transmission organization; and

2.2 Whereas, PG&E is registered with the North American Electric Reliability Corporation (NERC) as a Transmission Owner (TO), and as a Transmission Operator (TOP) in accordance with the NERC compliance registry process; and

2.3 Whereas, PG&E is a public utility providing both wholesale and retail electric power and energy sales and transmission and distribution services in northern and central California and owns an extensive electric transmission system within that area; and

2.4 Whereas, PG&E transferred operational control of its transmission system to the California Independent System Operator Corporation (CAISO), and is now a Participating Transmission Owner and a party to the CAISO's Transmission Control Agreement, under which PG&E is subject to the direction of the CAISO in the operation of its transmission system and under which the CAISO becomes the provider of transmission service over PG&E's transmission system, pursuant to the terms of the CAISO Tariff, the PG&E TO Tariff, Transmission Control Agreement, Scheduling Coordinator Agreement, and Utility Distribution Company Operating Agreement, all of which enable PG&E to satisfy the obligations of operating within the CAISO's Balancing Authority Area; and

2.5 Whereas, NCPA is a public agency engaged in the generation and transmission of electric power and energy and was created by a joint powers agreement first dated July 19, 1968, and as amended and restated January 1, 2008, entered pursuant to Chapter 5, Division 7, Title 1 of the California Government Code commencing with Section 6500; and

2.6 Whereas, the NCPA Member Customers are members of NCPA, and NCPA or other duly authorized entity acts as Scheduling Coordinator on their behalf; and

2.7 Whereas, NCPA has entered into certain agreements with the CAISO including, but not limited to, the Third Amended and Restated NCPA MSS Aggregator Agreement, as amended (NCPA MSS Agreement), and Scheduling Coordinator Agreement, and will have electric power delivered to or from it at each Point of Interconnection using transmission service available to it; and

2.8 Whereas, the NCPA Member Customers have individually or collectively entered into certain agreements with the CAISO including, but not limited to, the NCPA MSS Agreement and the Operating Agreement, and will have electric power delivered to or from each of their respective Points of Interconnection using transmission service available to it; and

2.9 Whereas, the relationships and obligations among NCPA and the NCPA Member Customers are determined under existing contracts and agreements among them, which this Agreement is not intended to alter; and

2.10 Whereas, this Agreement is intended to provide for the terms and conditions of interconnections between the Electric Systems of PG&E and the NCPA Parties and to replace the existing Interconnection Agreement made effective on July 12, 2002 ("Prior Agreement"), between them; and

2.11 Whereas, the Parties intend to replace the Existing Special Facilities Agreements that have been part of the Prior Agreement, and that provide for the interconnection of the existing generator units of the NCPA Parties with Large Generator Interconnection Agreements and Small Generator Interconnection Agreements, as applicable, among NCPA, PG&E and the CAISO; and

2.12 Whereas the Parties do not intend to change the underlying rights and responsibilities of the parties to the Special Facilities Agreements by transitioning to the new format of the Large Generator Interconnection Agreements and Small Generator Interconnection Agreements, or to impose additional requirements or obligations on existing NCPA generators; and

2.13 Whereas, the Parties agree to operate their respective Electric Systems in accordance with Good Utility Practice consistent with the requirements of this Agreement; and

2.14 Whereas, the Parties intend to cooperate in the operation of their respective Electric Systems to maximize their mutual benefits under this Agreement.

3 AGREEMENT

NOW, therefore, in consideration of the mutual covenants herein set forth, the Parties agree as follows:

4 DEFINITIONS

4.1 Use of Terms

As used in this Agreement (including the Recitals hereto), unless in any such case the context requires otherwise: The terms "herein," "hereto," "herewith" and "hereof" are references to this Agreement taken as a whole and not to any particular provision; the term "include," "includes" or "including" shall mean "including, for example and without limitation;" and references to a "Section," "subsection," "clause," "Appendix", "Schedule", or "Exhibit" shall mean a Section, subsection, clause, Appendix, Schedule or Exhibit of this Agreement, as the case may be. Unless otherwise specified in the Agreement, all references to a given agreement, instrument, tariff or other document, or law, regulation or ordinance shall be a reference to that agreement, instrument, tariff or other document, or law, regulation or ordinance as such now exists, including any amendment or modification made hereafter. A reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having a separate legal personality and includes its successors and permitted assigns. A reference to a "day" shall mean a calendar day

The following terms, when used in this Agreement with the initial letters capitalized, other than proper names, whether in the singular, plural or possessive, shall have the meanings indicated below. Capitalized terms not defined below shall have the meaning indicated in the Master Definitions Supplement included as Appendix A to the CAISO Tariff, provided, however, if a term as defined in this Agreement conflicts with the CAISO Tariff, the definition in this Agreement shall prevail.

4.1.1 Adverse Impact

An effect on a Party's Electric System resulting from a Modification, New Facility Addition, or Long-Term Change to Operations to another Party's Electric System that (1) materially degrades reliability of the affected Party's Electric System or (2) materially reduces the ability of the affected Party's Electric System to physically transfer power into, out of, or within said Electric System.

4.1.2 Agreement

This Interconnection Agreement among the Parties and its Appendices, as it may be amended.

4.1.3 Applicable Requirements

Any applicable law or regulation; and any standards, procedures or requirements of an entity with lawful authority to control or govern, including planning, the applicable transmission system (whether in full or in part) or the Balancing Authority Area in which a Party's Electric System is located, including but not limited to FERC, NERC, WECC, Peak Reliability, and a Balancing Authority.

4.1.4 Balancing Authority Area Arrangements

Arrangements, which may include, but is not limited to, an MSS or MSS Aggregator Agreement, between a Party and its Balancing Authority, or, if a Party is its own Balancing Authority, between a Party and WECC, in which the Party agrees to self-provide or procure the necessary resources and services and perform operations to meet Balancing Authority Area operating requirements and Applicable Requirements to maintain the operating reliability and integrity of the Balancing Authority Area's Electric System(s) in an economic manner consistent with Good Utility Practice.

4.1.5 Control Center

An Electric System's designated operations manager responsible for, among other things, its Electric System switching operations.

4.1.6 Cost

All just, reasonable, necessary and prudently incurred expenses or capital expenditures, including but not limited to those for operation, maintenance, engineering and facilities studies, Adverse Impact identification, Adverse Impact mitigation, contract modification, administrative and general expenses, taxes, depreciation, and fees for consultants, as determined in accordance with the FERC Uniform System of Accounts as such may be amended or superseded from time to time, and capital costs.

4.1.7 CPUC

The California Public Utilities Commission or its regulatory successor.

4.1.8 Direct Assignment Facilities

Facilities or portions of facilities that are owned by PG&E and which are necessary to physically and electrically interconnect the NCPA Parties to the CAISO Controlled Grid at the Points of Interconnection. All Direct Assignment Facilities that are contemplated by the Parties as of the Effective Date of this Interconnection Agreement are identified in the accompanying Transmission Facilities Agreements attached to and made part of this Agreement. Direct Assignment Facilities shall be subject to FERC approval.

4.1.9 Effective Date

The date specified as the Effective Date of this Agreement in Section 5.2 hereof.

4.1.10 Electric System

All properties and other assets, now or hereafter existing, which are leased to, licensed to, owned by, or controlled by a single person or entity, that are located within or interconnected to that person or entity's service area, and are used for or directly associated with the generation, transmission, transformation, distribution, purchase or sale of electric power, including all additions, extensions, expansions, and improvements thereto. To the extent a person or entity is not the sole owner of an asset or property, only that person's or that entity's ownership interest in such asset or property shall be considered to be part of its Electric System.

4.1.11 Engineering and Operating (E & O) Committee

A joint committee of the Parties established pursuant to Section 9.8.

4.1.12 Existing Contracts

The contracts between the Parties in existence on April 1, 1998 (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time or by order or requirement of FERC or any court having jurisdiction, provided that any contract shall cease to be an Existing Contract when its initially specified term ends, unless extended by agreement of the parties thereto, or when it may be earlier terminated; and contracts between PG&E and the Western Area Power Administration, and contracts between or tariffs involving PG&E and the Transmission Agency of Northern California, in which NCPA has a beneficial interest.

4.1.13 Facility Study

An engineering study to determine required Electric System modifications to accommodate a new Point of Interconnection or a modification of an existing Point of Interconnection, including the Cost and scheduled completion date for such modifications that will be required to provide needed services.

4.1.14 Interconnection Capacity

The rated maximum capability of Interconnection Facilities for power transfers at Points of Interconnection.

4.1.15 Interconnection Facilities

Electric facilities that establish or modify Points of Interconnection where PG&E's Electric System is connected to the Electric System of the NCPA Parties, or a Third Party. Interconnection Facilities may include, but are not limited to, transmission lines, towers and supports, switching stations, buses, breakers, switches, relays, transducers, transformers, meters, protective equipment, communications and telemetry devices, and land and land rights associated with the Interconnection Facilities at each Point of Interconnection.

4.1.16 Long-Term Change to Operations

An action intentionally taken, or an event permitted by a Party, that materially alters or modifies, on a long-term or permanent basis, the configuration or other operational characteristics of its Electric System. An action or event shall be deemed to have been taken, or to have occurred on a long-term basis if the action or event remains in effect for a period of more than 30 consecutive days or occurred on more than 60 days within any period of twelve (12) consecutive months. The following are examples of actions and events that qualify as a Long-Term Change to Operations when taken or occurring on a long-term basis, though this list is not exclusive:

(a) materially modifying a Remedial Action Scheme (RAS) or Special Protection Scheme (SPS), or disarming a RAS or SPS contrary to the manner and conditions for which it is designed to operate;

(b) opening switches that are generally kept closed under normal operating conditions, except in those cases where a modified switching configuration has been studied and agreed to by the affected Parties in accordance with Applicable Requirements;

(c) closing switches that are generally kept open under normal operating conditions, except in those cases where a modified switching configuration has been studied and agreed to by the affected Parties in accordance with Applicable Requirements;

(d) material changes to ratings or operating limits of any element of a Party's Electric System;

(e) disabling or materially changing the operation of a phase-shifting transformer;

(f) an increase in a Party's peak electric load on a Party's Electric System within a rolling twelve (12) month period that constitutes a ten (10) percent or greater increase over the Party's peak electric load from the prior twelve (12) month period;

(g) the planned shutdown of a generation facility with a generating capacity greater than 500 kW within any Party's Electric System, other than for routine maintenance; or

(h) actions or events similar in nature and/or effect to the foregoing.

A Long-Term Change to Operations as defined does not include (i) outages taken for maintenance or System Emergencies in accordance with Good Utility Practice; or (ii) actions taken during maintenance or to perform maintenance or respond to System Emergencies or (iii) actions taken by a Third Party, including the CAISO, that are beyond the control of the Parties.

4.1.17 Modification

The removal of or alteration or physical change to any element of a Party's Electric System.

4.1.18 New Facility Addition

The addition of a new transmission facility or the addition of a new generation facility directly connected to a Party's Electric System, whether owned by that Party or not.

4.1.19 PG&E Transmission Owner Tariff (PG&E TO Tariff)

PG&E Transmission Owner Tariff on file with FERC as PG&E FERC Electric Tariff Volume 5, as it may be modified or superseded from time to time.

4.1.20 PG&E Wholesale Distribution Tariff (PG&E WD Tariff)

PG&E Wholesale Distribution Tariff on file with the FERC as original PG&E FERC Electric Tariff Volume No. 4, as it may be modified or superseded from time to time.

4.1.21 Point(s) Of Interconnection

The physical connections of PG&E's transmission or distribution lines with NCPA or an NCPA Member Customer's Electric System as specified in Appendix A hereto, as that Appendix may be modified from time to time.

4.1.22 Operating Agreement

The Operating Agreement between Pacific Gas and Electric Company, Plumas-Sierra Rural Electric Cooperative, Northern California Power Agency and Sierra Pacific Power Company dated as of December 14, 2006, which describes and establishes the mutual responsibilities for operation of the interconnection points between PG&E and Plumas-Sierra Rural Electric Cooperation and Sierra Pacific Power Company and Plumas-Sierra Rural Electric Cooperation.

4.1.23 Remote Telemetry Unit (RTU)

A device that relays real-time information, including but not limited to kW, kVar, voltage, and breaker status, to a Party's Control Center or other designated recipient, to be used for monitoring purposes.

4.1.24 Responsible Meter Party

A Party having the responsibility for providing, installing, owning, operating, testing, servicing and maintaining meters and associated recording or telemetering equipment at each Point of Interconnection. Unless otherwise specified herein, NCPA and/or the applicable NCPA Member Customer who owns the meter or equipment in question shall be the Responsible Meter Party under this Agreement.

4.1.25 Service Area

That area within the geographic boundaries of the areas electrically served at retail, now or in the future, by the Parties.

4.1.26 System Impact Study

An engineering study conducted by or in coordination with PG&E at a NCPA Party's request to determine System Reinforcements required on PG&E's Electric System necessary to establish or modify a Point of Interconnection or to address a Significant Operational Change pursuant to Section 10.

4.1.27 System Reinforcements

Reinforcements to PG&E's Electric System, including but not limited to those identified by a System Impact Study, necessary to establish or maintain the Transfer Capability to a Point of Interconnection. System Reinforcements may be required when a Point of Interconnection is added or modified, when a Significant Operational Change pursuant to Section 10 is proposed, or when necessary to serve electric load reliably, or required by Good Utility Practice. System Reinforcements are limited to facilities required on PG&E's Electric System and ordinarily would not include Interconnection Facilities required at the Point of Interconnection.

4.1.28 Third Party

A person or entity that is not a Party to this Agreement.

4.1.29 Transfer Capability

The measure of the capability of interconnected Electric Systems to move or transfer power in a reliable manner from one point to another over all transmission lines between those points under specified system conditions.

4.1.30 Transmission Arrangement

An agreement or tariff, either the CAISO Tariff or a separate contract or tariff which enables NCPA to deliver power and energy to meet its electric power requirements.

4.1.31 Transmission Operations Center

PG&E’s Control Center from which it directs operations of its transmission system.

4.1.32 Transmission Facilities Agreement

An agreement made between one or more Parties for services, including, but not limited to, the design and installation of new facilities.

4.1.33 Uncontrollable Force

Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of PG&E or the NCPA Parties which could not be avoided through the exercise of Good Utility Practice.

4.1.34 Upgrade Facility

A new or upgraded Interconnection Facility and/or System Reinforcement constructed or installed pursuant to this Agreement.

5 SCOPE

5.1 Interconnected Operations

This Agreement governs the interconnected and coordinated operation of PG&E's Electric System, a portion of which has been turned over to the operational control of the CAISO, and the NCPA Parties' Electric Systems. As of the Effective Date of this Agreement, the CAISO operates the Balancing Authority Area in which the Parties operate their respective Electric Systems. The Parties agree that, during the term of this Agreement and unless otherwise provided for by amendment of this Agreement, that portion or those portions of the Parties' Electric Systems that are interconnected shall be operated in parallel pursuant to the terms and conditions of this Agreement and their respective Balancing Authority Area Arrangements. Each Party shall at all times to the maximum extent practicable avoid causing any Adverse Impact on another Party's Electric System.

5.2 Effective Date

The term "Effective Date" as used in this Agreement shall mean 0000 hours of November 1, 2015, or the date on which FERC accepts this Agreement for filing and permits it to be placed into effect without material change or material new conditions unacceptable to any Party, whichever is later.

If FERC sets this Agreement for hearing to determine whether it is just and reasonable and otherwise lawful, then this Agreement shall become effective on the date it is permitted to be placed into effect and subject to any conditions imposed by FERC. The ordering of such a hearing in and of itself shall not be considered a material change. However, in the event FERC makes any material change or imposes a material new condition unacceptable to any Party, the Parties shall promptly enter into good faith negotiations in an attempt to achieve a mutually agreeable modification to this Agreement to address any such material change or material new condition. The Parties agree to work diligently to obtain timely acceptance of this Agreement and all of its provisions by FERC, and agree that the NCPA Parties shall be entitled to prior review of PG&E's initial filing with FERC seeking acceptance of this Agreement for filing.

5.3 Termination

This Agreement shall terminate on the earliest of: (i) the occurrence of the fifth anniversary of the Effective Date or the tenth anniversary of the Effective Date if the Parties have agreed to such five-year extension by no later than the fourth anniversary of the Effective Date, where NCPA is authorized by the NCPA Member Customers to act on their behalf regarding such five-year extension; or (ii) the end of the 12th month following the date on which a Party gives the other Parties written notice that this Agreement shall be terminated, which notice shall not be given prior to the fourth anniversary of the Effective Date; or (iii) as provided in Section 10, 15, or 21. Notwithstanding the provisions of Section 5.3, if an NCPA Member Customer provides written notice to the other Parties to terminate the Agreement on the end of the 12th month following the date on which the NCPA Member Customer provides such written notice, the Agreement shall remain in full force and effect as to the remaining Parties. In addition, PG&E may give notice of termination to one NCPA Member Customer without terminating the agreement as to NCPA or any other NCPA Member Customers.

6 INTERCONNECTIONS

Transfer of electric power between the Electric Systems of PG&E and the NCPA Parties shall occur at the Point(s) of Interconnection identified in Appendix A.

6.1 Interconnection Capacity

Interconnection Capacity is determined by engineering studies that consider the physical rating of all equipment installed within the Interconnection Facilities at the Points of Interconnection. The E&O Committee shall periodically review the Interconnection Capacity to ensure that it is sufficiently maintained throughout the term of this Agreement. Unless otherwise agreed by the E&O Committee, any required engineering studies shall be performed by PG&E and the NCPA Parties or an engineering professional acting on behalf of the NCPA Parties, and reviewed with the E&O Committee. The Parties shall cooperate by providing any information necessary for such studies.

6.2 Establishing or Modifying Point(s) of Interconnection

Whenever NCPA or an NCPA Member Customer decides to add or modify a Point of Interconnection at transmission voltage, 60 kV or more, it shall so notify the CAISO, in accordance with the CAISO Tariff, and PG&E, in accordance with the PG&E TO Tariff. Upon PG&E's receipt of such notice, the Parties shall follow the procedures described in Sections 8 through 10 of the PG&E TO Tariff. Regarding disputes that might arise under this Section 6, if the PG&E TO Tariff conflicts with Section 22 of this Agreement, the PG&E TO Tariff shall govern.

If NCPA or an NCPA Member Customer decides to either modify or add a Point of Interconnection at distribution voltage, less than 60 kV, it shall so notify PG&E in accordance with the requirements of the PG&E WD Tariff. Upon PG&E's receipt of such notification, PG&E shall follow the applicable procedures and requirements of the PG&E WD Tariff to determine what Upgrade Facilities, if any, shall be required. Upgrade Facilities required for the addition or modification of a Point of Interconnection at distribution voltage shall be accomplished pursuant to the requirements of the PG&E WD Tariff. Regarding disputes that might arise under this Section 6 as related to service under PG&E WD Tariff, if the PG&E WD Tariff conflicts with Section 22 of this Agreement, the PG&E WD Tariff shall govern.

6.3 New Interconnection Facilities and Upgrades

If Upgrade Facilities are needed as a result of a NCPA or NCPA Member Customer notice to add or modify a Point of Interconnection pursuant to this Section 6, then PG&E, NCPA, and, if applicable the Member Customer issuing the notice shall meet and confer on a mutually acceptable plan to complete the Upgrade Facilities. The Cost responsibility for Upgrade Facilities required as a result of NCPA's or an NCPA Member Customer's notice to add or modify a Point of Interconnection shall be determined based on the provisions of Section 8.1.2 of the PG&E TO Tariff or Section 15 of the PG&E WD Tariff, as applicable, and Appendix C of this Agreement.

Any dispute regarding the actual capability of the existing transmission, distribution, or Interconnection Facilities, or the need for Upgrade Facilities, that will support the new or upgraded Point of Interconnection, or how the Cost responsibility for the necessary Upgrade Facilities should be allocated, shall be resolved through the dispute resolution procedures as set forth in Section 22.

6.4 Construction Plan and Agreement

Unless otherwise provided under the PG&E TO or WD Tariffs, or otherwise agreed to by the Parties, within thirty (30) calendar days after completion of a Facility Study as provided in the PG&E TO Tariff, NCPA or an NCPA Member Customer shall notify PG&E if it intends to proceed with the Upgrade Facility. PG&E, NCPA, and, if applicable, the notifying NCPA Member Customer shall then meet and confer on a mutually acceptable plan to complete the Upgrade Facility. If the conferring Parties reach agreement on a plan for construction or installation of an Upgrade Facility, including responsibility for payment of the applicable Cost, those Parties shall enter into a separate agreement pursuant to Appendix C. If the conferring Parties fail to reach such agreement, the matter should be resolved through the dispute resolution provisions in Section 22.

6.5 Test Period for Interconnection

The Parties shall cooperate in the testing of the Point(s) of Interconnection and of the Parties' Interconnection Facilities before they go into operation.

7 BALANCING AUTHORITY AREA ARRANGEMENTS

All transmission, distribution and generation facilities within a Party's Electric System shall at all times during the term of this Agreement be within a Balancing Authority Area and operated in accordance with Balancing Authority Area Arrangements. After a Party has had a reasonable opportunity to obtain or re-establish operation in a Balancing Authority Area or make the necessary Balancing Authority Area Arrangements, failure by a Party to operate in a Balancing Authority Area and to operate its Electric System in accordance with, and to maintain in effect, Balancing Authority Area Arrangements, shall be deemed a material breach of this Agreement and just cause for termination and disconnection of the Agreement as to such Party. If any Party operates without being located in an established Balancing Authority Area or without Balancing Authority Area Arrangements in effect, that Party shall fully indemnify and make whole the other Parties for any penalties, fees or costs imposed or other damages caused to those Parties.

Each Party shall act as its own Scheduling Coordinator or employ a Scheduling Coordinator to act for it. No Party shall have any obligation under this Agreement to serve as Scheduling Coordinator for another Party or take on any other role in which it acts on behalf of another Party as to its Party's transactions.

PG&E has and will have in effect various existing agreements with the Balancing Authority in which its Electric System is located. These agreements include, but are not limited to, the Transmission Control Agreement, the Transmission Owner Tariff, Scheduling Coordinator Agreements, Operating Agreement, and Utility Distribution Company Operating Agreement, all of which enable PG&E to satisfy the obligations of operating within the CAISO's Balancing Authority Area. This Agreement is subject to PG&E's obligations and responsibilities under those agreements, and in the event of any inconsistency between those agreements and this Agreement, the former shall control. NCPA and the NCPA Member Customers have and will have in effect various existing agreements with the Balancing Authority in which their Electric Systems are located. These agreements include, but are not limited to, the Scheduling Coordinator Agreement and NCPA MSS Agreement with the CAISO, the Operating Agreement, and such agreements qualified as Balancing Authority Area Arrangement that may be needed by the CAISO for operation of the Balancing Authority Area. This Agreement is subject to the NCPA Party's obligations and responsibilities under those agreements, and in the event of any inconsistency between those agreements and this Agreement, the former shall control.

8 SYSTEM PLANNING COORDINATION

Pursuant to the CAISO Tariff and Section 8 of this Agreement, PG&E conducts planning studies of its Electric System annually, including the reasonable use of information provided to PG&E pursuant to this Agreement, to identify System Reinforcements or other Modifications of its Electric System necessary to determine the Transfer Capability to reliably serve the expected loads connected to its Electric System, including expected NCPA and NCPA Member Customer loads at Point(s) of Interconnection.

8.1 Planning Process

In order for PG&E to include the effects of growth of the NCPA Parties' Electric System loads in its planning studies, each NCPA Party shall provide PG&E with their respective electric load planning forecast by October 1 of each year. Each NCPA Party shall also provide PG&E with certain network modeling data as required pursuant to Applicable Requirements, including NERC Standards MOD-010 and MOD-12, as such may be revised from time to time. Such electric load planning forecast shall contain the best estimate of its gross Electric System load (actual MW and MWh as measured at the Point of Interconnection plus generation resources internal to the Electric System) and net Electric System load (actual MW and MWh as measured at the Point of Interconnection) for the next five-year period. The initial forecast shall be submitted to PG&E within 30 days of the Effective Date. Both PG&E and the applicable NCPA Party or Parties shall be responsible for participating in planning for the construction of any necessary System Reinforcements as provided in the PG&E TO Tariff Sections 8 through 10. If PG&E disagrees with the electric load planning forecast provided by a NCPA Party, PG&E shall coordinate with NCPA and the impacted NCPA Member Customer, and if necessary, either Party may request that an E&O Committee meeting be scheduled pursuant to Section 9.8.1 to review and discuss PG&E's disagreement with the electric load planning forecast. Nothing in

Section 8 prevents PG&E from using, relying on, or incorporating alternative forecasts in planning studies.

8.2 System Reinforcements

If, as a result of its annual planning review process, PG&E determines, through studies conducted pursuant to the CAISO Tariff, including Section 4.8.1 thereof, and in accordance with PG&E TO Tariff Section 9, that a need exists to construct System Reinforcements that will have a direct effect on NCPA or an NCPA Member Customer, PG&E shall inform NCPA and, if applicable, the affected NCPA Member Customer through a notice pursuant to Section 31. Those Parties shall then follow the applicable procedures of the PG&E TO Tariff Sections 8 through 10.

9 OPERATING PROVISIONS

9.1 Good Utility Practice and Applicable Requirements Obligation

Each Party shall operate pursuant to this Agreement in accordance with Good Utility Practice and in compliance with Applicable Requirements of federal, state, and local laws, licenses, and permits. Each Party shall plan and operate its respective Electric System in accordance with Good Utility Practice and endeavor to minimize electrical disturbances on the Electric System of the other Party. No Party shall be obligated to operate in a manner contrary to Good Utility Practice. When satisfying its obligations pursuant to this Agreement, a Party shall in good faith, take all reasonable actions required to satisfy its obligations in accordance with Good Utility Practice and Applicable Requirements to timely avoid or mitigate Adverse Impacts to another Party's Electric System.

9.2 General

The Parties agree to coordinate the operations of their respective Electric Systems so as to avoid or minimize any Adverse Impacts to another Party's Electric System in accordance with Balancing Authority Area Arrangements.

9.3 Power Delivery and Quality Standard

Power delivered is commonly designated as three-phase alternating current, at nominal 60 Hertz, and at the nominal voltage described in Appendix A for each Point of Interconnection. Voltage and frequency fluctuations under system normal operation conditions shall be permitted consistent with Good Utility Practice.

Each Party shall plan, design, and operate its Electric System so as to minimize the interchange of reactive power at the Point(s) of Interconnections.

9.4 Coordination Of Operations

The Parties shall at all times coordinate and communicate their planned and unplanned outages and other switching operations that may have an effect on the operations of another Party's Electric System and may reasonably be required to protect the integrity of the Balancing Authority Area during System Emergencies.

PG&E, NCPA, and the NCPA Member Customers are also responsible for maintenance and switching operations of their Electric Systems. All Parties may from time to time remove various elements of their Electric Systems from operation or initiate other actions that may affect operations or transfer of energy across Point(s) of Interconnection.

The Parties shall coordinate their activities in the operation and maintenance of their Electric Systems in order to avoid or minimize any adverse effects of those activities on each other.

9.5 Relationship To Balancing Authority Area Operations

The Parties currently operate in the CAISO Balancing Authority Area. In the event that a Party makes any changes that significantly or materially affect its relationship with the CAISO, including, but not limited to, interconnecting its Electric System with a non-CAISO Balancing Authority Area, the Party making the change shall give a minimum of 30 days' notice to the other Parties.

9.6 Separate Balancing Authority Area

Nothing in this Agreement shall prevent or limit any Party from interconnecting with, joining or forming a new Balancing Authority Area. In such event, this Agreement shall be revised as appropriate to reflect such change in Balancing Authority Area operations.

9.7 Reporting Significant Events

Each Party shall promptly, after reporting to the Balancing Authority, report to the other Parties any System Emergency or other significant operating event reasonably likely to affect operation of the other Party's Electric System at each Point(s) of Interconnection. For notice to PG&E, such notice shall be by telephone to PG&E's Transmission Operations Center personnel or to a PG&E substation or switching center as may be designated by PG&E. For notice to NCPA or an NCPA Member Customer, such notice shall be by telephone to NCPA's Control Center, or as otherwise designated by NCPA or the NCPA Member Customer. Each Party, upon request and on a case-by-case basis for reasonable cause related to operating conditions, shall, in a timely manner, provide Electric System operating information, such as loading on lines and equipment and levels of operating voltages and electric power factors. In the event of an interruption(s), including but not limited to, power quality events, of electric service at any Point of Interconnection, the Party causing the interruption shall report, in a timely manner, to the affected Party or Parties the nature and suspected cause of the event, actions being taken to restore electric service, and the estimated time until restoration of electric service. Within 30 days following the restoration of electric service to the affected Parties, the Party causing the interruption shall provide a written report to the affected Parties identifying the cause of the interruption, and what preventive actions may be taken in the future to mitigate further interruptions in electric service to the affected Parties.

9.8 Engineering And Operating Committee

The Parties shall establish an Engineering and Operating (E&O) Committee. This “E&O Committee” shall jointly develop and modify, as necessary, operating procedures and engineering planning matters required to implement this Agreement. The E&O Committee shall consist of one representative designated in writing by each Party. Each Party shall also designate an alternate who may act instead of a representative at the option of that Party, and an NCPA Member Customer may designate NCPA to act as its alternate. Any Party may at any time change its representatives or alternate on the E&O Committee and shall promptly notify the other Parties of any change in designation. Any representative, by written notice to the other Parties, may authorize its alternate to act temporarily in its place. Each member of the E&O Committee may invite other members of its organization or others, as its advisors, to attend meetings of the E&O Committee.

The E&O Committee shall establish procedures for the coordination and operation of the Parties' Electric Systems, including, but not limited to, providing for the coordination of maintenance schedules and operation of the Parties' Electric Systems as may be required to maintain the reliability and power quality of the interconnected Electric Systems, minimize outages, reduce losses, maintain voltage levels, and minimize reactive interchanges. The E&O Committee shall also be responsible for examining and making recommendations to the Parties for Upgrade Facilities in order to:

(i) ensure that the Point(s) of Interconnection are operated in accordance with Good Utility Practice;

(ii) determine necessary additions or modifications to equipment or operating procedures to ensure that the Parties' Electric System reliability and service to its customers will not be adversely affected;

(iii) determine the studies that need to be performed and the manner in which the Cost of such studies shall be allocated unless the CAISO Tariff, PG&E TO Tariff or PG&E WD Tariff provides otherwise; and

(iv) make recommendations for the allocation of Costs associated with the Upgrade Facilities unless the CAISO Tariff, PG&E TO Tariff or PG&E WD Tariff provides otherwise.

9.8.1 E&O Committee Meetings

Any Party may call for a meeting of the E&O Committee upon reasonable advance notice to the other Parties. A written agenda incorporating any items proposed by the requesting Party shall be exchanged in advance of such meetings to the affected Parties. The meeting shall be timely scheduled, and the affected Parties shall select a meeting date that is mutually acceptable to the Parties. Meetings may be conducted in person, by telephone or by any other agreed-upon method. Meeting minutes shall be kept to document the discussions and outcome of the meetings, and such meeting minutes are to be distributed to the Parties.

9.8.2 E&O Committee Expenses

The expenses of the members of the E&O Committee, their alternates and advisors shall be borne by the Party they represent. Expenses incurred by the E&O Committee in addition to those herein above mentioned shall be shared in a just and reasonable manner agreed to by the Parties. The sharing of such expenses shall be agreed to prior to the time that such additional expenses are incurred.

9.8.3 E&O Committee Authority

The E&O Committee shall have no authority to modify any of the provisions of this Agreement. All actions, recommendations and reports shall become effective when signed, or otherwise approved, by all members of the E&O Committee and if necessary, referred to the Parties' respective management. Each Party's representatives shall be afforded ample time to review relevant details prior to finalizing any action, recommendation or report and may request up to 30 days to review the material to be acted upon.

9.9 Settlement of Disputes and Arbitration

The Parties agree to make best efforts to settle all disputes under this Agreement between the Parties as a matter of normal business practice under this Agreement. Any unresolved disputes shall be resolved through the dispute resolution procedure set forth in Section 22.

9.10 Protective Devices

Each Party shall, consistent with CAISO requirements and Good Utility Practice, install, modify, set and adjust any required protective relaying equipment associated with facilities within its respective Electric System at their own expense. Such settings, adjustments or replacement shall be consistent with settings, adjustments or replacement made by PG&E to PG&E's protective relaying equipment. The NCPA Parties shall install, modify, set, adjust or replace protective relaying equipment located within their respective Electric Systems in the event that such is required by PG&E's Modification of PG&E's Electric System consistent with CAISO requirements. Such changes shall be reviewed by the E&O Committee, unless otherwise agreed to by the affected Parties. The Parties shall exchange relay settings and fault duty information on a routine basis as agreed upon by the Parties.

9.11 Requirements for NCPA or NCPA Member Customer Operated Generators Connected to PG&E

NCPA or an NCPA Member Customer shall enter into a generator interconnection-type agreement with PG&E substantially consistent with CAISO’s Generation Interconnection Agreement, consistent with NCPA’s MSS Agreement, and consistent with Section 6 of this Agreement for each new generating facility operated by NCPA or an NCPA Member Customer, which is connected to PG&E’s Electric System at voltages of 60 kV or greater. NCPA or an NCPA Member Customer shall enter into a generator interconnection-type agreement with PG&E substantially consistent with PG&E’s Generator Interconnection Agreement under the PG&E WD Tariff, consistent with NCPA’s MSS Agreement and consistent with Section 6 of this Agreement for each new generating facility operated by NCPA or an NCPA Member Customer, which is connected to PG&E’s Electric System at voltages of less than 60 kV. This section 9.11 does not apply to NCPA or NCPA Member Customer generating facilities not connected to PG&E’s Electric System. The Parties will transition existing Special Facilities Agreements with PG&E to the appropriate Generator Interconnection Agreement, but this change is not intended to alter the rights or obligations of the Parties under the existing agreements.

9.12 Continuity Of Service

9.12.1 Operation Actions To Maintain Continuity

Each Party shall take actions that are reasonable and consistent with Balancing Authority Area Arrangements as necessary to maintain continuity of service between the Parties. Such actions may include, but are not limited to, opening or closing circuit breakers or other components of the interconnections.

9.12.2 Unscheduled Interruptions

A Party may temporarily interrupt or reduce any service, or temporarily separate all or any part of the facilities of its Electric System from another Party's Electric System to implement CAISO operating orders and their respective Balancing Authority Area Arrangements or Good Utility Practice at any time that: (i) a System Emergency exists, provided that if the unscheduled interruption is not undertaken pursuant to a CAISO operating order (a) such interruption, reduction of service or separation is necessary to remedy the System Emergency, and (b) the duration of such interruption, reduction of service or separation will be limited to as short a time period as reasonable under the circumstances; (ii) the action is necessary to prevent a hazard to life or property; or (iii) the operation of the Party's Electric System is suspended, interrupted or interfered with as a result of an Uncontrollable Force. Reasonable effort shall be made to coordinate any such interruption and such interruption will be immediately communicated to the affected Party. In the event of such interruption or reduction in service, the Parties shall restore full service on a basis comparable to the restoration of other public service and safety facilities and consistent with their respective Balancing Authority Area Arrangements.

9.12.3 Scheduled Interruptions

All scheduled interruptions of service shall be made as mutually agreed to by the Parties and in accordance with Balancing Authority Area Arrangements and Good Utility Practice. The Parties shall provide a minimum of 72 hours advance notice of any such interruption, reduction or separation, and its estimated duration.

9.12.4 Interruption By Protective Devices

The Parties utilize automatic protective devices in order to assist in maintaining the integrity and reliability of their respective Electric Systems and to protect their customers from damage, injury or prolonged outages. Service on the Parties' Electric Systems is subject to interruption in the event of operation of such devices. In the event of such interruption, service will be restored consistent with Good Utility Practice and Balancing Authority Area Arrangements. In addition, the Parties shall coordinate such restoration and all installations, upgrades, and replacements of protective devices at Point(s) of Interconnection.

9.12.5 Jeopardy

If at any time continuity of service within the CAISO Balancing Authority Area is being jeopardized due to failure of facilities, the Parties shall coordinate their responses to the situation in order to implement CAISO operating orders in accordance with their respective Balancing Authority Area Arrangements, Good Utility Practice, and any relevant standard promulgated by NERC or another body authorized to promulgate such standards. Such coordination may include the reduction of load; provided, except as otherwise set forth in the Parties' Balancing Authority Area Arrangements, such reduction shall maintain, as far as may be practicable, the relative sizes of load served by each Party in the same proportion as existed before such reduction so that no one Party is required to reduce its load disproportionately.

Any Party may also temporarily interrupt or reduce deliveries to Points of Interconnection or separate all or a part of the facilities of its Electric System from all or a part of the Electric System of another Party, or the Electric System that directly or indirectly serves another Party, if the first Party determines that the following conditions exist or that the described action is necessary: (i) a System Emergency; (ii) in order to install equipment on, make repairs or replacements to, make investigations and inspections of, or perform maintenance or other work on a Party's Electric System; (iii) to prevent a hazard to life or property; (iv) as necessitated by Good Utility Practice; or (v) where the operation of a Party's Electric System is suspended, interrupted or interfered with as a result of Uncontrollable Force. The Parties understand and agree that load curtailment under such circumstances should be coordinated among PG&E, NCPA, the relevant NCPA Member Customer(s) and the CAISO based upon the

CAISO Tariff and any Balancing Authority Area Arrangements entered into between the Parties and the CAISO. The Parties shall endeavor to provide notice to the affected Party prior to such interruptions or reductions of deliveries, and such interruptions or reductions of deliveries shall be minimized and implemented after all other practical remedies have been exhausted.

9.13 Operating Records

Each Party shall maintain operating records in accordance with Good Utility Practice. Each Party shall have reasonable access to such operating records kept by another Party which reasonably relate to interconnected operation of the Parties' Electric Systems; provided, that if requested to do so by the other Party, a Party requesting such records shall be required to keep such records confidential pursuant to Section 9.14. Such records shall include, but not be limited to, operating logs, scheduled transfers through each Point of Interconnection, line loadings, outage and power quality reports, voltages and reactive power.

9.14 Confidentiality

The Parties anticipate that during the course of the Parties’ relationship under this Agreement, they will at times supply copies of confidential or proprietary information to each other, including information that should be kept confidential from and not disclosed to certain departments within a Party (e.g., transmission planning information that cannot be disclosed to marketing personnel) or to Third Parties, including the public. If PG&E supplies confidential information to NCPA and/or one or more NCPA Member Customers, or NCPA or one or more NCPA Member Customer supplies confidential information to PG&E, it is the responsibility of the supplying Party to inform the receiving Party that such information is confidential and to label or otherwise mark each confidential document or electronic file “CONFIDENTIAL”. It shall be the responsibility and obligation of the receiving Party to maintain the confidentiality of such information in accordance with the supplying Party’s reasonable instructions, and to not disclose information designated confidential to any Third Party or entity to whom disclosure is prohibited under applicable regulations (e.g., the FERC Standards of Conduct), unless required to do so by law.

If a Party ("Receiving Party") receives a request from a Third Party, whether under the California Public Records Act, California Government Code Sections 6250-6270, as amended, or otherwise, for access to, or inspection, disclosure or copying of, any of the other Party's (the "Supplying Party") confidential data or information ("Disclosure Request"), then the Receiving Party shall provide notice to and a copy of the Disclosure Request to the Supplying Party within three (3) business days of receipt of the Disclosure Request. Within three (3) business days of receipt of such notice, the Supplying Party shall provide notice to the Receiving Party either:

(a) that the Supplying Party believes there are reasonable legal grounds for denying or objecting to the Disclosure Request, and the Supplying Party requests the Receiving Party to deny or object to the Disclosure Request with respect to identified confidential information. In such case, the Supplying Party will either defend the denial of the Disclosure Request at its sole Cost (with reasonable assistance by the Receiving Party), or it shall indemnify the Receiving Party for all Costs associated with denying or objecting to the Disclosure Request. Such indemnification by the Supplying Party of the Receiving Party shall include all of the Receiving Party's Costs reasonably incurred with respect to denial of or objection to the Disclosure Request, including but not limited to Costs, penalties, and the Receiving Party's attorneys' fees; or

(b) that the Supplying Party shall agree that the Receiving Party may grant the Disclosure Request without any liability by the Receiving Party to the Supplying Party.

10 SIGNIFICANT REGULATORY OR OPERATIONAL CHANGE

The procedures set forth in this Section 10 shall apply in the event of a Significant Regulatory Change or a Significant Operational Change as described below.

10.1 Significant Regulatory Change

A "Significant Regulatory Change," as this term is used in this Section 10, shall be deemed to occur if FERC, the CPUC, the CAISO or any other court, public authority, governmental, or other lawfully established civilian authorities having jurisdiction, issues an order or decision or adopts or modifies a tariff or filed contract, or enacts a law that materially interferes with the ability of any Party to perform any of its obligations under this Agreement.

10.2 Significant Operational Change

A "Significant Operational Change," as this term is used in this Section 10, shall consist of any of the following: (i) a Party making a new interconnection of its Electric System with the Electric System of a Third Party, including any generation, that would have an Adverse Impact on the operation of another Party's Electric System; (ii) installation, operation, termination, or expansion by a Party or a Third Party of a generation facility within any Party's Electric System where power or energy from such generation is intended to or may possibly flow through a Point of Interconnection and create an Adverse Impact on another Party's Electric System; (iii) a Long-Term Change to Operations; (iv) any other operational change proposed by a Party that could reasonably be expected to create an Adverse Impact on another Party's Electric System; (v) material amendments and/or revisions to any tariffs, contracts or other applicable documents referenced in this Agreement that directly affect a Party's obligations under this Agreement, including, but not limited to, the CAISO Tariff, PG&E's TO Tariff or PG&E's WD Tariff; or (vi) an action taken by the Balancing Authority that may have a material detrimental impact on the way a Party operates or must operate its Electric System or the Points of Interconnection between the Parties.

10.3 Change in Functions or Scope

The Parties recognize that there may be a change in the functions performed by the CAISO or in the scope of the facilities under the operational control of the CAISO, or the replacement of the CAISO with a Regional Transmission Organization that may perform different functions or have a different scope than the CAISO as of the Effective Date. Such a change shall not be deemed to be a Significant Regulatory Change unless the conditions described in Section 10.1 and 10.2 of this Agreement are satisfied. Any transfer from PG&E to the CAISO of any functions contemplated in this Agreement can be a Significant Regulatory Change if the conditions described in Section 10.1 and 10.2 of this Agreement are satisfied.

10.4 Notification of Significant Regulatory or Operational Change

At any time during the term of this Agreement, if any Party anticipates the occurrence of a Significant Regulatory Change that may reasonably be expected to create an Adverse Impact on any Parties' obligations or operations under this Agreement or Significant Operational Change, such Party shall provide written notice to the affected Parties as soon as practicable. The notice shall contain a description of the change, including expected time schedules, and of the effect of the significant change to the affected Party's Electric System. If the Party giving notice believes that it will be necessary to amend this Agreement to address the anticipated change, then the notice to the other Party may include a proposal that the Parties meet to negotiate an appropriate amendment to this Agreement. The Parties shall promptly enter into good faith negotiations and attempt to achieve a mutually agreeable modification to this Agreement to address any such significant change. If a Party is uncertain as to whether a proposed change might be Significant or might create an Adverse Impact, or if it wishes to have certainty under Section 10.8 before proceeding, the Party should also give notice to the potentially Affected Party as soon as practicable. Notwithstanding the foregoing, where the potential Significant Operational Change is studied in or is the result of the CAISO generator interconnection process ("CAISO Generator Change"), a Party is not obligated to give notice under this Section 10.4, provided that the Parties are notified in writing of the CAISO Generator Change in accordance with the CAISO Tariff in reasonable time to allow the other Parties the opportunity to express concerns and to provide information to the study conducted in accordance with the CAISO generator interconnection planning process.

10.5 Amendment of Agreement

If the Parties agree that an amendment to this Agreement is necessary to address a Significant Regulatory Change or a Significant Operational Change, the Parties will proceed to negotiate such amendment. If the Parties have not reached agreement within 60 calendar days of the date of the first meeting, any unresolved issues may be submitted for resolution through the dispute resolution procedures set forth in Section 22; provided that all Parties agree to such procedures. After the 60-day period stated above, any Party may, but is not required to, unilaterally initiate an appropriate proceeding respecting this Agreement with FERC pursuant to

Sections 205 or 206 of the FPA, which proceeding could include a request for termination of this Agreement, and another Party may exercise its rights under the FPA to protest or oppose such filing. In the event of filing for termination, PG&E shall make an appropriate regulatory filing of a replacement agreement such that the replacement agreement is effective contemporaneously with the termination date of this Agreement.

10.6 Studies of Significant Operational Change

The Party receiving notice of a Significant Operational Change will respond to the Party submitting such notice within 30 days. If the Party receiving such notice believes that there will be no Adverse Impact resulting from the Significant Operational Change, it shall so state. If the Party receiving notice of a Significant Operational Change believes that the proposed change may reasonably be expected to have an Adverse Impact on the operation of its Electric System, it may request a study of any such Significant Operational Change to determine the potential for any Adverse Impacts and any potential avoidance or mitigation measures thereto. The affected Parties shall cooperate in determining the scope of the study and how the study should be conducted, and shall cooperate to provide information necessary to conduct such a study in a timely manner. NCPA may, at its sole discretion, act on behalf of a NCPA Member Customer and participate in determining the scope of the study and how the study should be conducted if NCPA is not an affected Party. To the extent studies are required, those studies will be performed in a reasonable period of time.

If it is determined, based on the results of the study, that, in addition, a Facility Study or System Impact Study is required, such study shall be performed within the time and in the manner specified in Section 10 of the PG&E TO Tariff and as agreed by the Parties. All study Costs associated with a proposal shall be the responsibility of the Party whose proposal or actions will cause the Significant Operational Change, or will be split into two equal shares by (1) PG&E and (2) the NCPA Parties if the CAISO is the entity that causes or will cause the change; provided, that such Costs may be paid by a responsible Third Party and that NCPA Parties shall be responsible for dividing their share of such Costs among themselves. Any disputes over the necessity of particular studies or the Cost of such studies shall be resolved through the dispute resolution procedures set forth in Section 22 unless the dispute resolution procedures of the PG&E TO Tariff or the PG&E WD Tariff apply. Upon completion of necessary studies, the Parties will each review the study results and discuss any recommendations for avoidance and/or mitigation of Adverse Impacts.

10.7 Mitigation And Costs

Unless otherwise agreed by the Parties, the Party whose proposal or action causes the Significant Operational Change ("Modifying Party") shall be responsible for avoiding or fully mitigating an Adverse Impact to the Electric System of an affected Party ("Affected Party"), and to the extent Adverse Impacts cannot be avoided or fully mitigated, fully compensating the Affected Party for all Costs incurred pursuant to the Adverse Impact; provided, that such Costs may be paid by a responsible Third Party. Any reasonable Cost incurred by the Affected Party in its cooperation with the Modifying Party shall be reimbursed by the Modifying Party. All avoidance or mitigation measures shall be completed before the Significant Operational Change is made. Any dispute regarding the need for, the nature of, or the Cost of mitigating Adverse Impacts or compensating the Affected Party for those Adverse Impacts that cannot be mitigated shall be resolved through the dispute resolution procedures set forth in Section 22.

In the event changes in transmission delivery voltages, relocation of facilities serving Points of Interconnections or other changes in transmission facilities are necessary on PG&E's side of any Point of Interconnection with NCPA or an NCPA Member Customer because of changes to PG&E's transmission as a result of Good Utility Practice or CAISO planning requirements, these changes shall be made by PG&E at its expense. For similar changes made to NCPA's or an NCPA Member Customer's side of Point(s) of Interconnection, such changes shall be at NCPA's or the NCPA Member Customer's expense unless the change is made for PG&E's benefit and at PG&E's sole discretion or as otherwise agreed. Such change made at PG&E's sole discretion shall be submitted to the E&O Committee for its determination of respective long term benefits of such changes, if any. The E&O Committee shall recommend a methodology for allocating the Cost of such changes based on the projected net long-term benefits to each Party. Changes required on PG&E's side due to any changes made for NCPA's or an NCPA Member Customer's benefit and at NCPA's or an NCPA Member Customer's sole discretion shall be made at NCPA's or the NCPA Member Customer's expense, unless submitted to the E&O

Committee for its determination of an appropriate allocation between the Parties based on projected net long term benefits to each Party.

Notwithstanding the provisions of this Section 10.7, the Modifying Party will not be responsible for their share of any Costs associated with the changes made under this Section that are approved by FERC, or other jurisdictional authority, for inclusion in the Affected Party's Transmission Revenue Requirement for recovery through Access Charges, as provided in Section 26 of the CAISO Tariff. Nothing in the foregoing sentence obligates or requires the Affected Party to seek recovery for any specific Costs in their Transmission Revenue Requirement.

10.8 Failure To Notify Of Significant Operational Changes

Each Party has a duty to provide notice to any Affected Parties of Significant Operational Changes planned for its Electric System that could reasonably be expected to have an Adverse Impact on the Electric System of those Parties. If a Party implements a Significant Operational Change without providing such notice, the Affected Party shall have the right to open any affected Point(s) of Interconnection if, in its judgment, it is necessary to protect the integrity of its Electric System, and the right to file with FERC under Sections 205 or 206 of the FPA seeking appropriate relief, including, but not limited to, amendment or termination of this Agreement, except that the termination of this Agreement by an NCPA Member Customer will not be deemed to terminate this Agreement as to NCPA or any other NCPA Member Customer.

11 INSTALLATION AND ACCESS

Where it is necessary for any Party to install any of its facilities on another Party's premises in order to accomplish the Interconnection or otherwise to perform the duties contemplated by this Agreement, the Parties hereby grant to each other, subject to any legal and regulatory requirements for any specific installation, for the term of this Agreement: i) the right to make such installation along the mutually agreed route (subject to each Party's right to protect its operations or that of its customers in its Service Area) of sufficient width to provide full legal clearance from all structures on such property; and ii) access to each Party's premises upon reasonable notice and at reasonable hours for any purposes reasonably connected with this Agreement.

No Party shall be allowed or obligated to install such facilities unless and until all necessary licenses, permits, certificates, or other governmental authorizations or approvals that may be necessary are obtained and any necessary easements for the installation of facilities are granted. Electric facilities belonging to one Party that are installed on another Party's premises will be relocated only with the agreement of the owner of such facilities, which shall not be unreasonably withheld. The requesting Party shall pay the Cost, if any, of any such facility relocation. If such Costs are FERC jurisdictional, PG&E shall request and obtain FERC acceptance to assess such Costs prior to collection.

12 METERING

12.1 Delivery Meters

All real and reactive power deliveries shall be metered at each Point of Interconnection with meters meeting the requirements of: (i) the CAISO Tariff for interconnections at 60 kV and above; and (ii) the PG&E WD Tariff for interconnections below 60 kV. Any conflicts with regard to metering standards that may arise between this Agreement, the PG&E WD Tariff, or the CAISO Tariff shall be resolved consistent with the applicable tariff. Power deliveries shall be metered at delivery voltages described in Appendix A. At a minimum, the Responsible Meter Party shall meter all power flowing across each Point of Interconnection in either direction. The Parties shall cooperate in the installation and provision of access to the meters, as necessary for each Party to obtain the information needed to perform as contemplated under this Agreement.

12.2 Requirements For Meters And Meter Maintenance

The Responsible Meter Party is obligated to install and maintain metering equipment, including where necessary RTUs, in accordance with CAISO standards, at each Point of Interconnection that shall measure and record real and reactive power flows and shall be capable of recording flows in both directions. Such "in" and "out" meters shall be designed to prevent reverse registration and measure and continuously record such deliveries.

12.3 The NCPA Parties' Obligation To Provide Meter Data To PG&E

NCPA and the NCPA Member Customers, pursuant to the NCPA MSS Agreement, subject to any exemptions granted by the CAISO, supplies the CAISO with both telemetry and settlement quality meter data for each Point of Interconnection. The telemetry data includes generator status, voltage and energy output. NCPA or an NCPA Member Customer will be the Responsible Meter Party for each meter and will grant PG&E access to the same metering data in accordance with the NCPA MSS Agreement. NCPA or an NCPA Member Customers shall also grant PG&E access to metering data that is supplied to the CAISO in accordance with the NCPA MSS Agreement that is associated with generating units interconnected to the Electric System of NCPA or an NCPA Member Customers. NCPA or an NCPA Member Customer will reasonably cooperate with PG&E to ensure that PG&E can successfully access metering data under this Section 12.3. Should the NCPA MSS Agreement terminate for any reason, the Parties shall cooperate in determining an alternative method for supplying PG&E the same level of access to data as it had under the NCPA MSS Agreement and this Agreement.

In addition, where there is real-time telemetry of NCPA or NCPA Member Customer generation facilities and transmission interconnections of one (1) MW or larger, NCPA and/or NCPA Member Customers shall provide PG&E with the available real-time telemetry via the existing PG&E to NCPA Inter-Control Center Protocol ("ICCP") data link.

12.4 Consequences of Failing to Provide Meter Data

In the event that the Responsible Meter Party fails to provide to PG&E access to available meter data in accordance with Section 12.3, PG&E shall be entitled to make reasonable assumptions necessary for the operation of its transmission system. The assumptions shall be based on reasonably available information including, but not limited to, records of historical usage, available data and meter readings and general characteristics of NCPA or the NCPA Member Customers' operation and facilities.

12.5 Periodic Meter Testing

All meters necessary to operate each Point of Interconnection shall be installed, tested, and maintained in accordance with the CAISO Tariff and Good Utility Practice, and shall be tested periodically by the Party owning the meter, at intervals consistent with the CAISO Tariff, and at any other reasonable time upon request by PG&E (if an NCPA Party) or NCPA or an NCPA Member Customer (if PG&E). Meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be inspected, tested, or adjusted, and representatives of PG&E (if an NCPA Party) or the NCPA Parties (if PG&E) shall be afforded reasonable opportunity to be present upon such occasions. Notwithstanding a Party's obligation to afford reasonable opportunity for other Parties to be present for meter inspections, testing or adjustments, if metering equipment that is used to collect settlement qualify data requires immediate maintenance or repair, such maintenance or repair may be completed by the owning Party at is sole discretion.

13 BILLING AND PAYMENT

PG&E shall bill NCPA and/or an NCPA Member Customer, and NCPA and/or an NCPA Member Customer shall pay any amounts owed to PG&E pursuant to this Agreement in accordance with Appendix D. NCPA and/or an NCPA Member Customer shall bill PG&E, and PG&E shall pay any amounts owed to NCPA and/or an NCPA Member Customer pursuant to this Agreement, where Sections D.1 through D.9 of Appendix D shall hereto apply to PG&E's payment obligations to NCPA and/or an NCPA Member Customer, substituting "NCPA" and/or "NCPA Member Customer" for "PG&E", respectively, in accordance with Appendix D.

14 ACCOUNTING

14.1 Accounting Procedures

The Parties shall record relevant Cost(s) and maintain accounting records in accordance with generally accepted accounting practices and as to PG&E the FERC Uniform System of Accounts.

14.2 Audit Rights

For good cause and upon reasonable notice, each Party shall have the right to audit, at its own expense, the relevant records of PG&E (if an NCPA Party) or NCPA or an NCPA Member Customer (if PG&E) for the limited purpose of determining whether the other Party is meeting its obligations under this Agreement. Such audits shall be limited to only those records reasonably required to determine compliance with this Agreement, and each Party agrees to disclose the information obtained in such audit only to those persons, whether employed by such Party or otherwise, that are directly involved in the administration of this Agreement and that are permitted to have access to such information under applicable regulations, including the FERC Standards of Conduct. Each Party agrees that under no circumstances will it use any information obtained in such an audit for any commercial purpose or for any purpose other than assuring enforcement of this Agreement. The right to audit shall be limited to data for two prior years from the date of the final billing for a matter or from the date of the questioned event, as applicable.

15 ADVERSE DETERMINATION OR EXPANSION OF OBLIGATIONS

15.1 Adverse Determination

If, after the Effective Date of this Agreement, FERC or any other regulatory body, agency or court of competent jurisdiction determines that all or any part of this Agreement, its operation or effect is unjust, unreasonable, unlawful, imprudent or otherwise not in the public interest, each Party shall be relieved of any obligations hereunder to the extent necessary to comply with or eliminate such adverse determination. The Parties shall promptly enter into good faith negotiations in an attempt to achieve a mutually agreeable modification to this Agreement to address any such adverse determination.

15.2 Expansion Of Obligations

If, after the Effective Date of this Agreement, FERC or any other regulatory body, agency or court of competent jurisdiction orders or determines that this Agreement should be interpreted, modified, or significantly extended in such a manner that a Party may be required to extend its obligations under this Agreement to a Third Party, or to incur under this Agreement significant new or different obligations to another Party or to Third Parties not contemplated by this Agreement, then the Parties shall be relieved of their obligations to the extent lawful and necessary to eliminate the effect of that order or determination, and the Parties shall attempt to renegotiate in good faith the terms and conditions of the Agreement to restore the original balance of benefits and burdens contemplated by the Parties at the time this Agreement was made.

15.3 Renegotiation

If, within three months after an order or decision as described in Sections 15.1 and 15.2, the Parties either: (i) do not agree that a renegotiation is feasible or necessary; or (ii) the Parties cannot agree to amend or supersede this Agreement, then: (a) any Party may initiate dispute resolution in accordance with Section 22; (b) PG&E may unilaterally file an amendment to this Agreement or a replacement agreement; or (c) the NCPA Parties may take any action before the FERC or elsewhere which it deems appropriate. The effect of any termination under this Section 15.3, and the rights of the Parties thereunder, shall be as provided in Sections 36 and 37. As used in this Section 15.3, the term “Agreement” includes both this Agreement and any tariff, rate or rate schedule that in whole or in part results from this Agreement.

16 ASSIGNMENT

16.1 Consent Required

No transfer or assignment of the rights, benefits or duties of any Party under this Agreement shall be effective without the prior written consent of the other Parties except as provided herein, which consent shall not be withheld unreasonably; provided, that this Section 16 shall not apply to interests that arise by reason of any deed of trust, mortgage, indenture or security agreement heretofore granted or executed by any Party. No partial assignment of the rights, benefits or duties of any Party shall be permitted under this Agreement unless otherwise agreed to by PG&E (if an NCPA Party) or NCPA and the NCPA Member Customers (if PG&E), except that the NCPA Parties may assign the rights, benefits and duties under this Agreement among themselves at their discretion.

16.2 Assignee's Continuing Obligation

Any successor to or transferee or assignee of the rights or obligations of a Party, whether by voluntary transfer, judicial sale, foreclosure sale or otherwise, shall be subject to all terms and conditions of this Agreement to the same extent as though such successor, transferee, or assignee were an original Party.

17 CAPTIONS

All indices, titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of the Agreement.

18 CONSTRUCTION OF THE AGREEMENT

Ambiguities or uncertainties in the wording of the Agreement shall not be construed for or against any Party.

19 CONTROL AND OWNERSHIP OF FACILITIES

The Electric System of a Party shall at all times be and remain in the exclusive ownership, possession and control of the Party, or licensed or leased to that Party as provided in the applicable arrangement, and nothing in this Agreement shall be construed to give another Party any right of ownership, possession or control of all or any portion of that Electric System. All facilities owned and installed by one Party hereunder shall, unless otherwise agreed by the Parties, at all times be and remain the property of that Party, except that the NCPA Parties may transfer ownership of property among themselves at their discretion.

20 COOPERATION AND RIGHT OF ACCESS AND INSPECTION

Each Party shall give to the others all necessary permission to enable it to perform its obligations under the Agreement. PG&E shall give to the NCPA Parties, and the NCPA Parties to PG&E, the right to have their agents, employees and representatives, on reasonable notice and accompanied by the agents, employees and representatives of the other Party, enter its premises at reasonable times and in accordance with reasonable rules and regulations for the purpose of inspecting the property and equipment of the other Party to the extent necessary and in a manner that is reasonable for assuring the performance of the Parties under the Agreement.

21 DEFAULT

21.1 Termination For Default

If any Party breaches its material obligations under this Agreement, such breach shall constitute an event of default. If any Party defaults under this Agreement, another Party may terminate this Agreement as to the defaulting Party; provided that prior to such termination the non-defaulting Party must provide the defaulting Party with written notice stating: 1) the non-defaulting Party's intent to terminate; 2) the date of such intended termination; 3) the specific grounds for termination; 4) specific actions that the defaulting Party must take to cure the default, if any; and 5) a reasonable period of time, which shall not be less than 60 calendar days, within which the defaulting Party may take action to cure the default and avoid termination, provided there is any action which can be taken to cure the default. Termination shall not become effective without approval by FERC. Application of dispute resolution pursuant to Section 22 with regard to separate disputes shall not be deemed to limit the right to terminate this Agreement under this Section 21.1. Notwithstanding the right of a non-defaulting Party to terminate this Agreement pursuant to Section 21.1, if less than all of the NCPA Member Customers exercise such right, the Agreement shall remain in full force and effect as to the remaining Parties. Nor will the default of one or more NCPA Member Customers allow termination of the Agreement with respect to NCPA itself or the other NCPA Member Customers.

21.2 Other Remedies For Default

The remedy under Section 21.1 is not exclusive and, subject to Section 22, any Party shall be entitled to pursue any other legal, equitable or regulatory rights and remedies it may have in response to a default by another Party.

22 DISPUTE RESOLUTION

The Parties shall make best efforts to resolve all disputes arising under this Agreement expeditiously and by good faith negotiation. Where this Agreement specifically calls for resolution of disputes pursuant to this Section 22, the Parties shall pursue dispute resolution according to the provisions of Appendix B.

23 GOVERNING LAW

This Agreement shall be interpreted, governed by and construed under the laws of the State of California, as if executed and to be performed within the State of California.

24 INDEMNITY

24.1 Definitions

As used in this Section 24, with initial letters capitalized, whether in the singular or the plural, the following terms shall have the following meanings:

24.1.1 Accidents

(a) Accidents sustained by a Third Party (“Claimant”), which is an ultimate use customer of a Party;

(b) arises out of delivery of, or curtailment of, or interruption to electric service, including but not limited to abnormalities in frequency or voltage; and

(c) results from either or both of the following:

(i) engineering, design, construction, repair, supervision, inspection, testing, protection, operation, maintenance, replacement, reconstruction, use, or ownership of any Party's Electric System; or

(ii) the performance or non-performance of any Party's obligations under the Agreement.

24.2 Indemnity Duty

If a Claimant makes a claim or brings an action against a Party seeking recovery for loss, damage, Costs or expenses resulting from or arising out of an Accident the following shall apply:

24.2.1 That Party shall defend any such claim or action brought against it, except as otherwise provided in this Section 24.2.

24.2.2 A Party ("Indemnitor") shall hold harmless, defend and indemnify, to the fullest extent permitted by law, PG&E (if such claim or action is brought against an NCPA Party) or NCPA or an NCPA Member Customer (if such claim or action is brought against PG&E), its directors or members of its governing board, officers and employees ("Indemnitees"), upon request by the Indemnitee, for claims or actions brought against the Indemnitee allegedly resulting from Accidents caused by acts, errors or omissions of the Indemnitor.

24.2.3 No Party shall under this Agreement be obligated to defend, hold harmless or indemnify another Party, its directors or members of its governing board, officers and employees for Accidents resulting from the latter's gross negligence or willful misconduct.

24.2.4 In the event a dispute under this Section 24 is litigated, each Party specifically agrees to pay its own incurred Costs including attorney's fees, expert and consultant fees, and other Costs of litigation.

25 JUDGMENTS AND DETERMINATIONS

When the terms of this Agreement provide that an action may or must be taken, or that the existence of a condition may be established based on a judgment or determination of a Party, such judgment shall be exercised or such determination shall be made reasonably and in good faith, and where applicable in accordance with Good Utility Practice and shall not be arbitrary or capricious.

26 LIABILITY

26.1 To Third Parties

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any Third Party.

26.2 No Consequential, Special or Indirect Damages from Breach

Except for its willful action, gross negligence, or with respect to breach of this Agreement or the indemnity duty under Section 24.2, no Party, nor its directors or members of its governing board, officers, employees or agents shall be liable under this Agreement to another

Party for any loss, damage, claim, Cost, charge or expense arising from or related to this Agreement. In the event of breach of this Agreement, no Party, nor its directors or members of its governing board, officers, employees or agents shall be liable under this Agreement to another Party for any consequential, special or indirect damages.

26.3 Protection Of A Party's Own Facilities

Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or non-operation of PG&E's (if an NCPA Party) or NCPA's or an NCPA Member Customers' (if PG&E) facilities, and such other Party shall not be liable for any such damage so caused; provided, this limitation on liability shall not extend to failure to observe the requirements of Section 10.

26.4 Liability For Interruptions

PG&E shall not be liable to the NCPA Parties, and the NCPA Parties shall not be liable to PG&E, and each hereby releases the others and their directors, members of their governing board, officers, employees and agents from and indemnifies them, to the fullest extent permitted by law, for any claim, demand, liability, loss or damage, whether direct, indirect or consequential, incurred by either, that results from the interruption or curtailment in accordance with i) this Agreement, ii) Good Utility Practice, or (iii) as directed by the CAISO, of power flows through a Point of Interconnection under this Agreement.

27 NO DEDICATION OF FACILITIES

Any undertaking by any Party under any provision of this Agreement is rendered strictly as an accommodation and shall not constitute the dedication by the first Party of any part or all of its Electric System to the other, the public, or any Third Party. Any such undertaking by any Party under a provision of, or resulting from, this Agreement shall cease upon the termination of that Party's obligations under this Agreement.

28 NO OBLIGATION TO OFFER SAME SERVICE TO OTHERS

By entering into this Agreement to interconnect with the NCPA Parties or any Third Party at NCPA's or an NCPA Member Customer's request, and filing it with FERC, PG&E does not commit itself to furnish any like or similar undertaking to any other person or entity.

29 NO PRECEDENT

This Agreement establishes no precedent with regard to any other entity or agreement. Nothing contained in this Agreement shall establish any rights to or precedent for other arrangements as may exist, now or in the future, between the Parties for the provision of any interconnection arrangements, interconnection service, or any form of electric service.

30 NO OTHER SERVICES PROVIDED

No Party undertakes under this Agreement the obligation to provide or make available any transmission service, distribution service, power or energy sales or services or Ancillary Services for any other Party or any Third Party, unless otherwise agreed to by a Party, and where such provision or receipt of services will be made pursuant to a separate agreement. Provided, however, this Agreement does not supersede rights or obligations as provided in Existing Contracts.

30.1 Limitation on Parties Obligation

The Parties specifically intend that this Agreement shall relate only to their rights and obligations pertaining to the interconnection of their Electric Systems. Under this Agreement, no Party undertakes to provide or make available any Balancing Authority Area services, transmission service, distribution service, power or energy sales or services or Ancillary Services for any other Party or any Third Party, and in no circumstance shall anyParty be responsible under this Agreement for providing any such services.

This Agreement does not supersede rights or obligations as provided in any other agreement between any or all of the Parties. Nothing in this Agreement shall prevent any Party from seeking an order under Section 211 or 212 of the FPA.

30.2 Transmission Arrangements

The NCPA Parties are currently party to several contracts that, among other things, provide Transmission Arrangements for the delivery of power to NCPA Parties' Electric Systems. Nothing in this Agreement shall interfere with the NCPA Parties' rights, including those for transmission services, provided under such contracts. All Parties may make Transmission Arrangements, other than or in addition to such service provided from the CAISO.

31 NOTICES

31.1 Written Notices

Any notice, request, declaration, demand, information, report, or item otherwise required, authorized or provided for in this Agreement shall be given in writing, except as otherwise provided in this Agreement, and shall be deemed properly given if delivered personally or by facsimile transmission (fax), sent by first class United States Mail or overnight or express mail service, postage or fees prepaid, or through electronic communication where such electronic communication shall be deemed delivered on the first business day following delivery, to each of the persons specified below:

(1) <u>To NCPA</u>:
Randy Howard
General Manager
Northern California Power Agency
651 Commerce Drive
Roseville, CA 95678

and

Tony Zimmer
Supervisor, Industry Restructuring & Interconnection Affairs
Northern California Power Agency
651 Commerce Drive
Roseville, CA 95678

(2) To PG&E:

Mr. David Rubin
Director, Service Analysis
Pacific Gas and Electric Company
Mail Code N9P
P.O. Box 770000
San Francisco, CA 94177

With a copy to:

Mr. Yilma Hailemichael
Manager, Transmission Contract Management
Pacific Gas and Electric Company
Mail Code B13L
P.O. Box 770000
San Francisco, CA 94177

and

Mr. Bruce Henry
Director, Transmission System Operations
Pacific Gas and Electric Company
Mail Code B15A
P.O. Box 770000
San Francisco, CA 94177

(3) To City of Alameda:

Glenn Steiger
General Manager
Alameda Municipal Power
2000 Grand Street
Alameda, CA 94501

(4) To City of Biggs:

Mark Sorensen
City Administrator
City of Biggs
P.O. Box 307
465 "C" Street
Biggs, CA 95917

(5) To City of Gridley:

City Administrator
City of Gridley
685 Kentucky Street
Gridley, CA 95948

(6) To City of Healdsburg:

Terry Crowley
Electric Utility Director
City of Healdsburg
401 Grove Street
Healdsburg, CA 95448

(7) To City of Lodi:

Elizabeth Kirkley
Utility Director
City of Lodi
1331 South Ham Lane
Lodi, CA 95242

(8) To City of Lompoc:

Larry Bean

Utility Department Director

City of Lompoc

P.O. Box 8001

100 Civic Center Plaza

Lompoc, CA 93438

(9) To City of Palo Alto:

Valerie Fong

Utilities Director

City of Palo Alto

250 Hamilton Avenue

Palo Alto, CA 94301

(10) To Plumas-Sierra Rural Electric Cooperative:

Bob Marshall

General Manager

Plumas-Sierra Rural Electric Cooperative

73233 Highway 70

Portola, CA 96122

(11) To City of Ukiah:

Mel Grandi

Utility Director

City of Ukiah

300 Seminary Avenue

Ukiah, CA 95482

31.2 Changes Of Notice Recipient

Any Party may change its designation of the person who is to receive notices on its behalf by giving the other Parties notice thereof in the manner provided in this Section 31. No more than three persons shall be designated by a Party to receive notices.

31.3 Routine Notices

Any notice of a routine character in connection with service under this Agreement or in connection with the operation of facilities shall be given in such a manner as the Parties may determine is appropriate from time to time, unless otherwise provided in this Agreement.

31.4 Reliance On Notice

Every Party shall be entitled under this Agreement to rely on another Party's notice when given (or not given, when a Party fails to provide notice within the time prescribed) as having all necessary approvals of that other Party's management, Board of Directors or other governing body, and any notice (or failure to provide timely notice) hereunder shall be binding on the noticing Party and shall obligate that Party to make such payments or to perform such duties as are necessarily associated with the notice or, if a Party fails to provide timely notice, that failure to give notice.

32 RESERVATION OF RIGHTS

Nothing contained herein shall be construed as affecting in any way the Parties' rights under Sections 205 and 206 of the FPA or the regulations promulgated thereunder. The term "rates" as used herein shall mean a statement of rates and charges for or in connection with the services provided for in this Agreement, and all classifications, practices, rules or regulations that in any manner affect or relate to such rates and charges. PG&E may unilaterally make application to FERC for a change in rates, including rate methodology and the terms and conditions of service, under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder. Any party may seek changes to the terms of this Agreement pursuant to Section 206 of the FPA. Nothing contained herein shall be construed as affecting in any way the right of the NCPA Parties to oppose such a change under Section 205 or FERC's rules and regulations or to exercise its rights under Section 206 of the FPA or FERC's rules and regulations.

33 RESPONSIBILITY FOR PAYMENTS AND SECURITY

All Parties shall be fully responsible and liable to each other for payments to be made under this Agreement. The Parties shall perform unconditionally and fully each and every obligation that each has under this Agreement; provided, that this Agreement shall not restrict any right any Party may otherwise have to pledge any of its revenues, funds, assets, rights, property or interests therein. A Party's status as a creditor shall not be subordinate to the interest of any creditor, subject to any pledge or debt obligation, provision of law or existing obligations of a Party.

34 RULES AND REGULATIONS

The Parties may propose, from time to time, changes to such procedures, rules, or regulations as they shall determine are necessary in order to establish the methods of operation to be followed in the performance of this Agreement or requirements of the Balancing Authority; provided, that any such procedure, rule, or regulation shall not be inconsistent with the provisions of this Agreement. If a Party objects to a procedure, rule, or regulation proposed by another Party, it will notify the other Parties and the Parties will endeavor to modify the procedure, rule, or regulation in order to resolve the objection. No such procedure, rule or regulation shall be adopted absent the mutual written consent of the Parties.

35 SEVERABILITY

If any term, covenant or condition of this Agreement or its application is held to be invalid as to any person, entity or circumstance, by FERC or any other regulatory body, or agency or court of competent jurisdiction, then such term, covenant or condition shall cease to have force and effect to the extent of that holding. In that event, however, all other terms, covenants and conditions of this Agreement and their application shall not be affected thereby, but shall remain in full force and effect unless and to the extent that a regulatory agency or court of competent jurisdiction finds that a provision is not separable from the invalid provision(s) of this Agreement.

36 CONTINUING RIGHTS OF THE NCPA PARTIES UPON TERMINATION

Upon termination of the Agreement, the NCPA Parties shall continue to have such rights, if any, to be connected to PG&E's Electric System that are provided by law, regulation or other contract or agreement; provided, that the existence of this Agreement, after its termination, shall not be used by any Party to establish or defeat the existence of any rights provided by law, regulation or other contract or agreement. Termination of this Agreement, if accepted or approved by FERC, also shall terminate any other tariff or rate schedule that in whole or in part results from this Agreement, to the extent not inconsistent with a Party's aforementioned rights at law. After termination of this Agreement and any required FERC acceptance or approval of such termination, all obligations and rights provided under this Agreement or such tariff or rate schedule shall cease, and no Party shall claim or assert any continuing right other than as may be provided by law, regulation or other contract or agreement. Such termination shall not affect rights and obligations of a continuing nature or for payment of money for goods or services provided prior to termination. This Section shall not be construed as a bar to the assertion by the NCPA Parties of any rights it may have to service following termination of this Agreement, independent and exclusive of the Agreement.

37 RIGHTS OF PG&E UPON TERMINATION

Should FERC deny, condition, suspend or defer PG&E's notice of termination, PG&E shall under no circumstances be required to maintain any interconnections or to provide any services, based in whole or in part on the existence of this Agreement, beyond the minimum time necessary for compliance with FERC's denial, condition, suspension or deferral.

38 WAIVER OF RIGHTS

Any waiver at any time by any Party of its rights with respect to a default under the Agreement, or with respect to any other matter arising in connection with the Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right shall not constitute or be deemed a waiver.

39 UNCONTROLLABLE FORCES

A Party shall not be considered to be in default in the performance of any obligation under the Agreement (other than an obligation to make payments for bills previously rendered pursuant to the Agreement) when a failure of performance is the result of Uncontrollable Forces.

40 ENTIRE AGREEMENT AND AMENDMENTS

PG&E and the NCPA Parties agree that the provisions of this Agreement constitute the entire agreement between them regarding the subject matter of the Agreement and the Parties' rights and obligations with respect thereto. This Agreement is intended to be the complete and exclusive statement of the terms of the Parties' agreement that supersedes all prior and contemporaneous offers, promises, representations, negotiations, discussions or communications between PG&E and the NCPA Parties that may have been made in connection with the subject matter of this Agreement. No representation, covenant, or other matter, oral or written, that is not expressly set forth, incorporated, or referenced in this Agreement (except for applicable laws and regulations) shall be a part of, modify, or affect this Agreement.

This Agreement may be modified by written agreement of the Parties. Each subpart of Appendix A of this Agreement may be modified by the written agreement of PG&E and the NCPA Member Customer to whose Point(s) of Interconnection that subsection applies, without the agreement of any other Party.

41 NO THIRD PARTY RIGHTS OR OBLIGATION

No right or obligation contained in this Agreement shall be applied or used for the benefit of any person or entity that is not a Party.

42 WARRANTY OF AUTHORITY

Each Party warrants and represents that this Agreement has been duly authorized, executed and delivered by such Party and constitutes the legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency, reorganization, or similar laws effecting the enforcement of creditor's rights.

43 COUNTERPARTS

This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument and as if all the signatories to all of the counterparts had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

44 APPENDICES INCLUDED

The following Appendices to this Agreement, as they may be revised from time to time by written agreement of the Parties or by order of FERC, are attached hereto and are incorporated by reference as if fully set forth herein:

Appendix A — Points of Interconnection
Appendix B — Dispute Resolution and Arbitration
Appendix C — Upgrade Facilities
Appendix D — Billing and Payments
Appendix E — Operational Coordination

45 EXECUTION

IN WITNESS THEREOF, the Parties have, by signature of its duly authorized representative shown below, executed and delivered a counterpart of this Agreement.

NORTHERN CALIFORNIA POWER AGENCY

By: [signature]

Name: Randy Howard

Title: General Manager

Date: 9/11/15

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________

Name: David Rubin

Title: Director, Service Analysis

Date: ______________________

CITY OF ALAMEDA

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

NORTHERN CALIFORNIA POWER AGENCY

By: ______________________

Name: Randy Howard

Title: General Manager

Date: ______________________

PACIFIC GAS AND ELECTRIC COMPANY

By: David Rubin

Name: David Rubin

Title: Director, Service Analysis

Date: August 5, 2015

CITY OF ALAMEDA

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

NORTHERN CALIFORNIA POWER AGENCY

By: ____________________

Name: Randy Howard

Title: General Manager

Date: ____________________

PACIFIC GAS AND ELECTRIC COMPANY

By: ____________________

Name: David Rubin

Title: Director, Service Analysis

Date: ____________________

CITY OF ALAMEDA

By: ____________________

Name: GLENN D. STEIGER

Title: GENERAL MANAGER

Date: SEPT. 17, 2015

CITY OF BIGGS

By: Roger L Frith

Name: Roger L. Frith

Title: MAYOR

Date: 9/18/15

CITY OF GRIDLEY

By: __________________________

Name: __________________________

Title: __________________________

Date: __________________________

CITY OF HEALDSBURG

By: __________________________

Name: __________________________

Title: __________________________

Date: __________________________

CITY OF BIGGS

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF GRIDLEY

By: ______________________

Name: Daryl Dye

Title: Gridley Electrical Superintendent

Date: 9/17 2015

CITY OF HEALDSBURG

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF BIGGS

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF GRIDLEY

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF HEALDSBURG

By: ______________________

Name: David Mickaelian

Title: City Manager

Date: 9/25/15

CITY OF LODI

By: ______________________

Name: Stephen Schwabauer

Title: City Manager

Date: 9/24/15

APPROVED AS TO FORM:

Janice D Magdich, City Attorney

ATTEST:

Jennifer M Ferraiolo

Jennifer Ferraiolo, City Clerk

CITY OF LOMPOC

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF PALO ALTO

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF LODI

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF LOMPOC

By: Bob C

Name: Bob Lingl

Title: Mayor City of Lompoc

Date: 9/28/2015

CITY OF PALO ALTO

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF LODI

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF LOMPOC

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF PALO ALTO

By: ______________________

Name: for James Keene

Title: CITY MANAGER

Date: 9-18-15

PLUMAS SIERRA RURAL ELECTRIC COOPERATIVE

By: ______________________

Name: Robert W. Marshall

Title: General Manager/CEO

Date: 9/21/15

CITY OF UKIAH

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

PLUMAS SIERRA RURAL ELECTRIC COOPERATIVE

By: ______________________

Name: ______________________

Title: ______________________

Date: ______________________

CITY OF UKIAH

By: ______________________

Name: Sage Sangiacomo

Title: City Manager

Date: 9-18-15

APPENDIX A
POINTS OF INTERCONNECTION

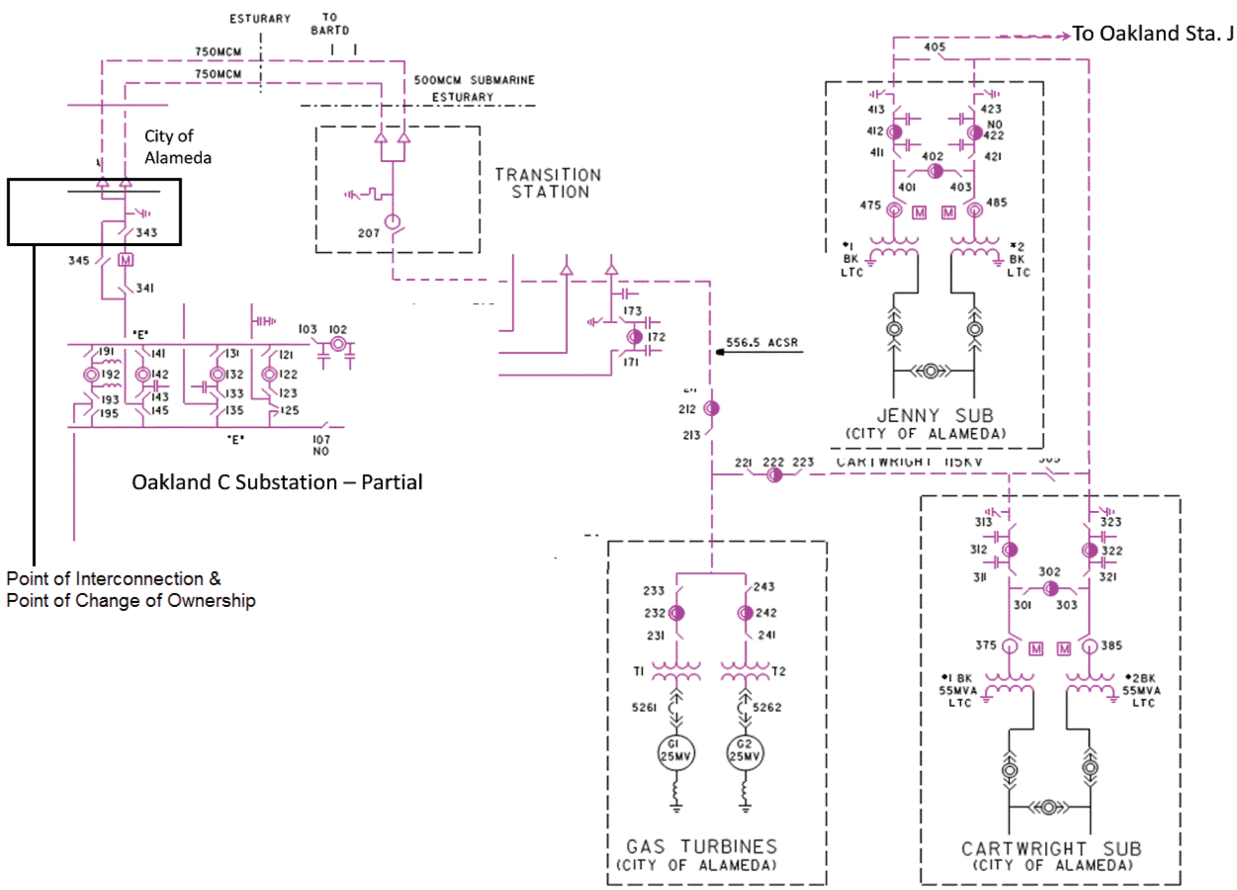
NCPA Member Customer	**Point(s) of Interconnection**	**Voltage (kV)**
Alameda	Oakland Substation C and Oakland Substation J	115 (Both Points)
Biggs	Biggs Sub (60 kV and 12 kV)	60 and 12[1]
Gridley	Gridley Sub	60
Healdsburg	Healdsburg Sub	60
Lodi	Industrial Sub (Lodi Line 1 and Lodi Line 2); and White Slough STIG[2]	60 (Both Industrial Points) 230 (White Slough STIG)
Lompoc	Lompoc Sub (Lompoc Line 1 and Lompoc Line 2)	115 (Both Points)
Palo Alto	Colorado Sub (Palo Alto Line 1, Palo Alto Line 2, and Palo Alto Line 3)	115 (All 3 Points)
Plumas Sierra	Quincy Sub	60
Ukiah	Babcock Sub	115

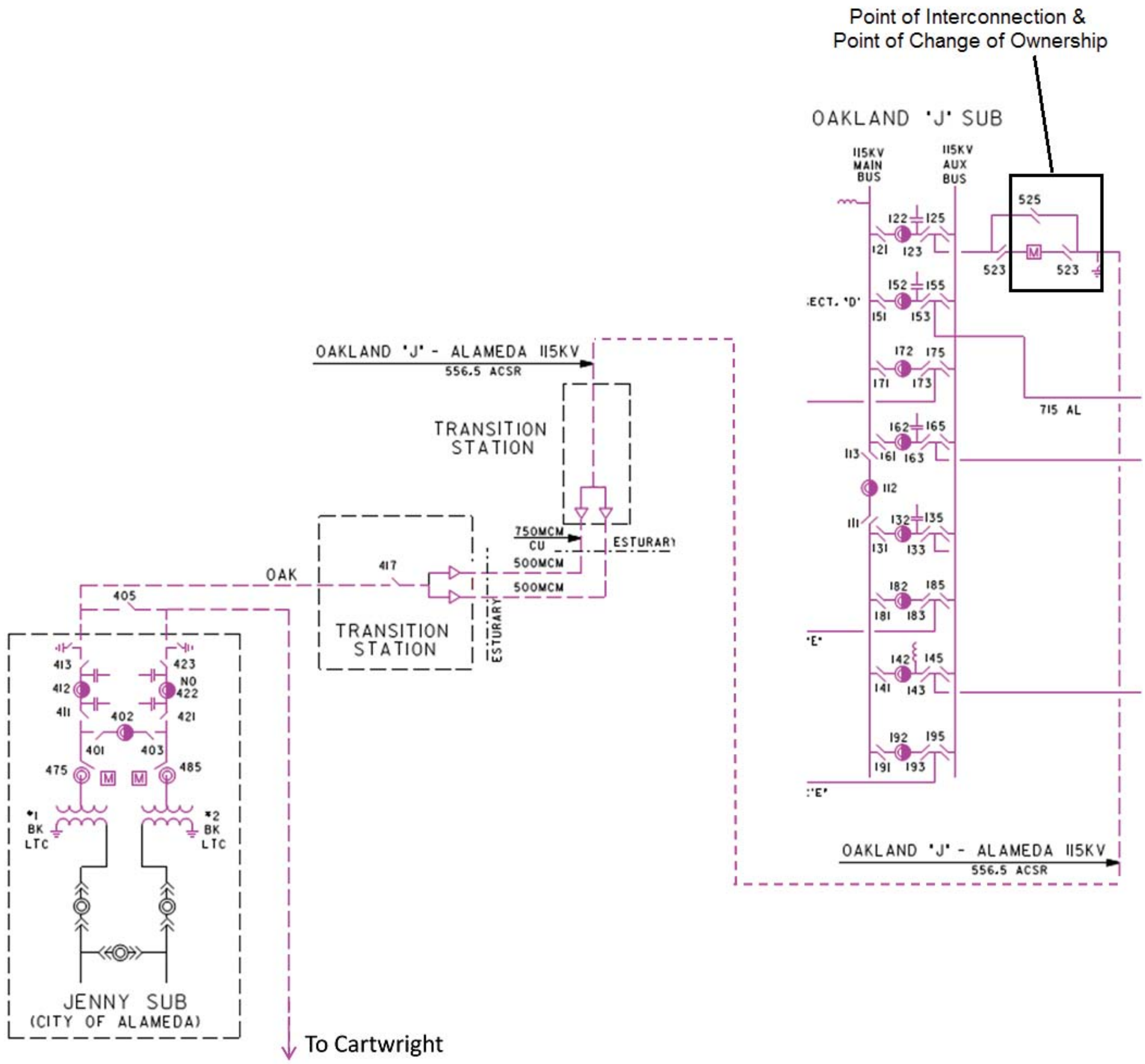
1 As set forth in the Interruptible Wholesale Distribution Service and Interconnection Agreement between PG&E and the City of Biggs ("12 kV Agreement"), PG&E Rate Schedule FERC No. 246, PG&E's 12 kV system and the facilities needed to retain the connection with the City of Biggs shall only be used for delivery in emergency conditions or during scheduled maintenance of the 60 kV system and only on an as available and interruptible basis, after notification by the party requesting such use. Notwithstanding anything in this Agreement or the 12 kV Agreement, PG&E may take the 60 kV system out of operation or schedule maintenance on the 60 kV system regardless of available capacity on the 12 kV system; provided, however, that PG&E otherwise communicates and coordinates planned outages with NCPA and the City of Biggs in accordance with Section 9.4 of this Agreement.

2 Lodi Wastewater treatment plant Load will be served via the Lodi White Slough STIG Interconnection with PG&E, be separately metered, and be included in the normal, coincident and non-coincident Load information for Lodi.

CITY OF ALAMEDA SCHEMATICS
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

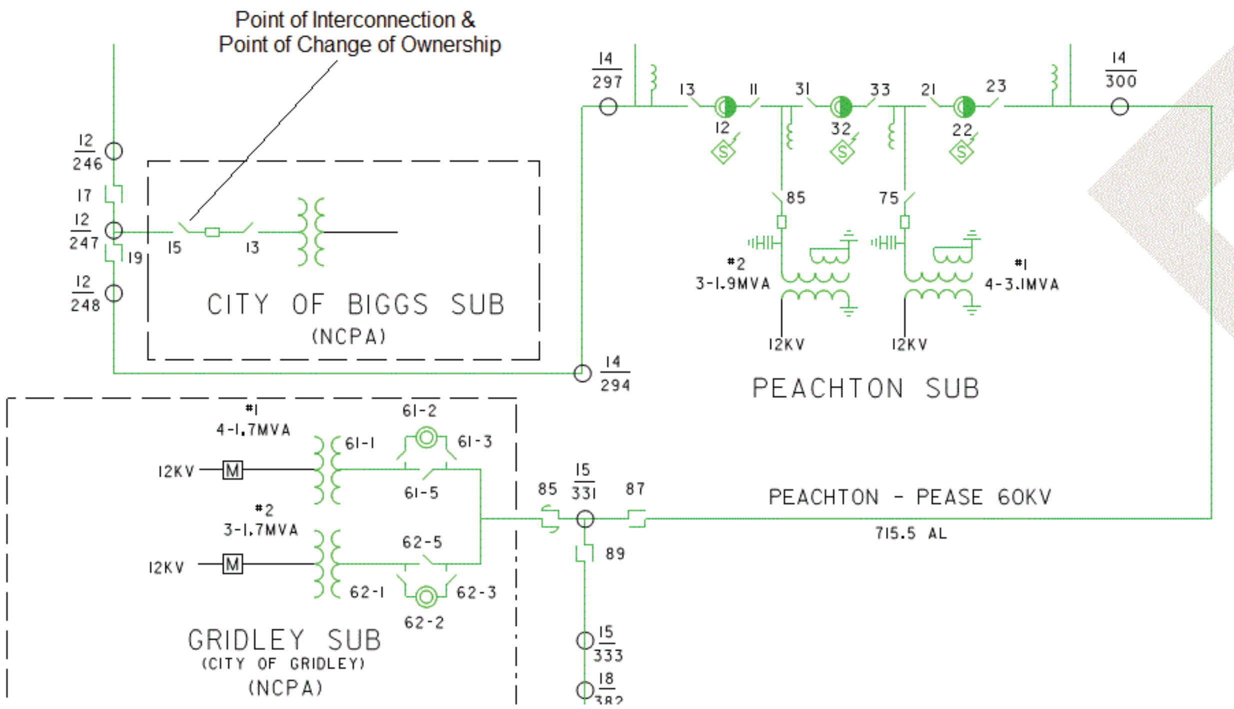
The following are single-line diagrams of the City of Alameda's ("Alameda") Interconnection Facilities at the Points of Interconnection that identifies the owner of such Interconnection Facilities.




Point of Interconnection &
Point of Change of Ownership
OAKLAND 'J' SUB
115KV MAIN BUS
115KV AUX BUS
525
523
523
OAKLAND 'J' - ALAMEDA 115KV
556.5 ACSR
TRANSITION STATION
750MCM CU
500MCM
500MCM
ESTURARY
OAK
417
405
TRANSITION STATION
ESTURARY
715 AL
JENNY SUB
(CITY OF ALAMEDA)
#1 BK LTC
#2 BK LTC
OAKLAND 'J' - ALAMEDA 115KV
556.5 ACSR
To Cartwright

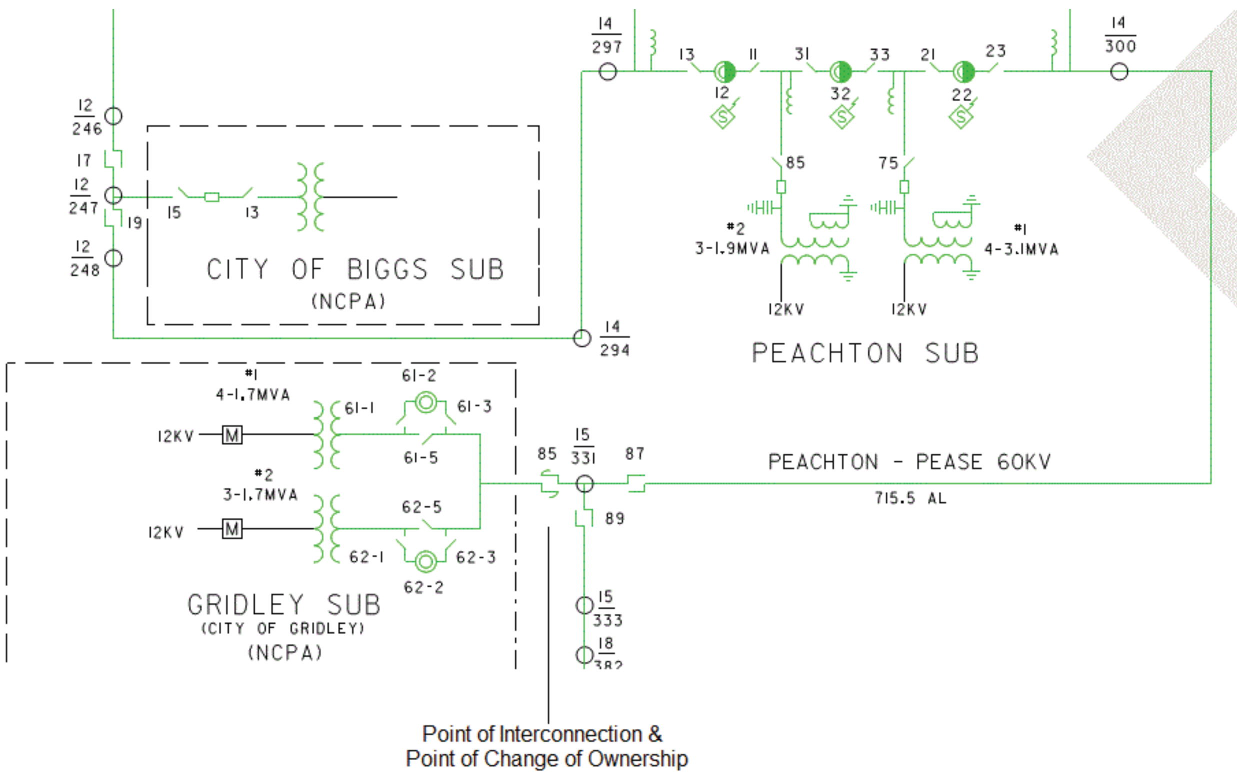
CITY OF BIGGS SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Biggs' ("Biggs") Interconnection Facilities at the Point of Interconnection that identifies the owner of such Interconnection Facilities.



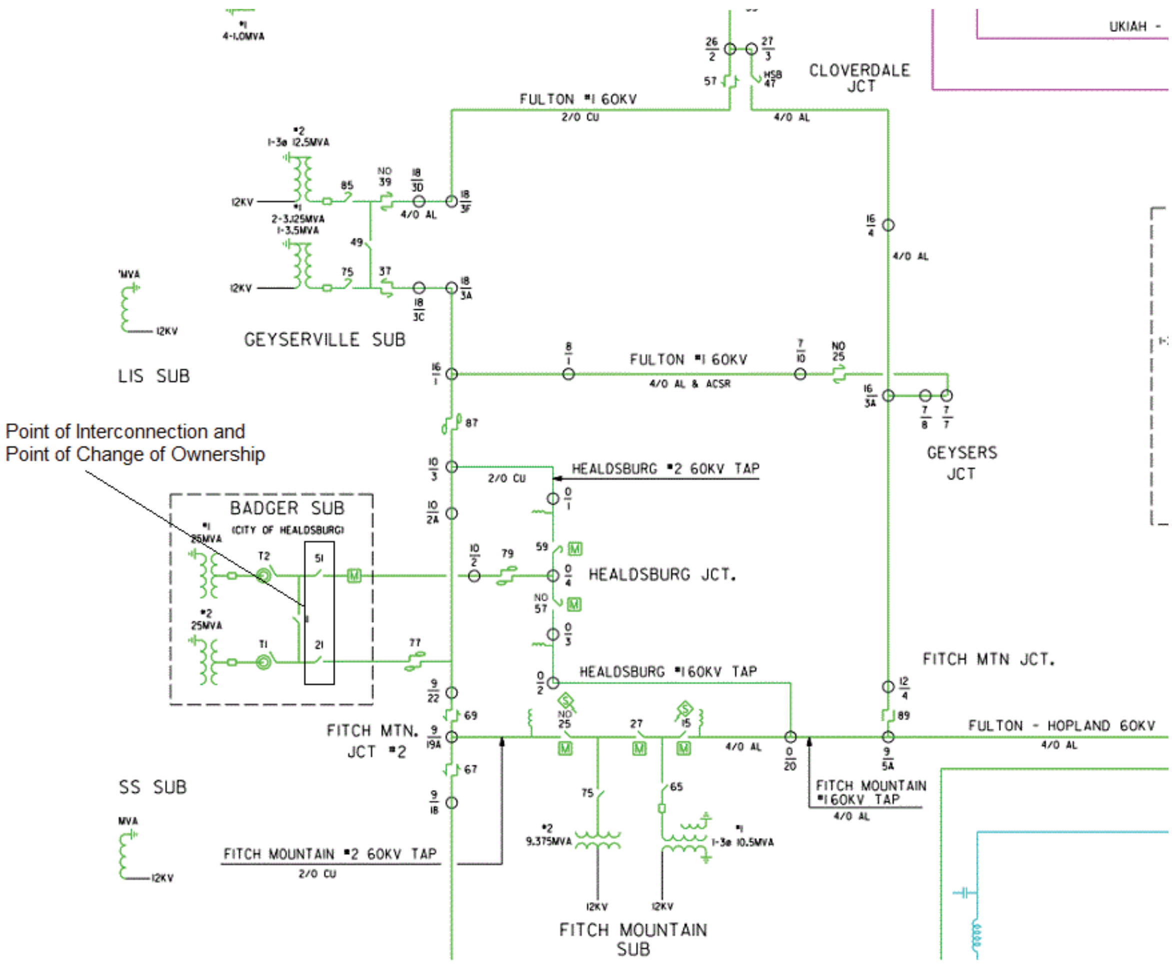
CITY OF GRIDLEY SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Gridley's ("Gridley") Interconnection Facilities at the Point of Interconnection that identifies the owner of such Interconnection Facilities.



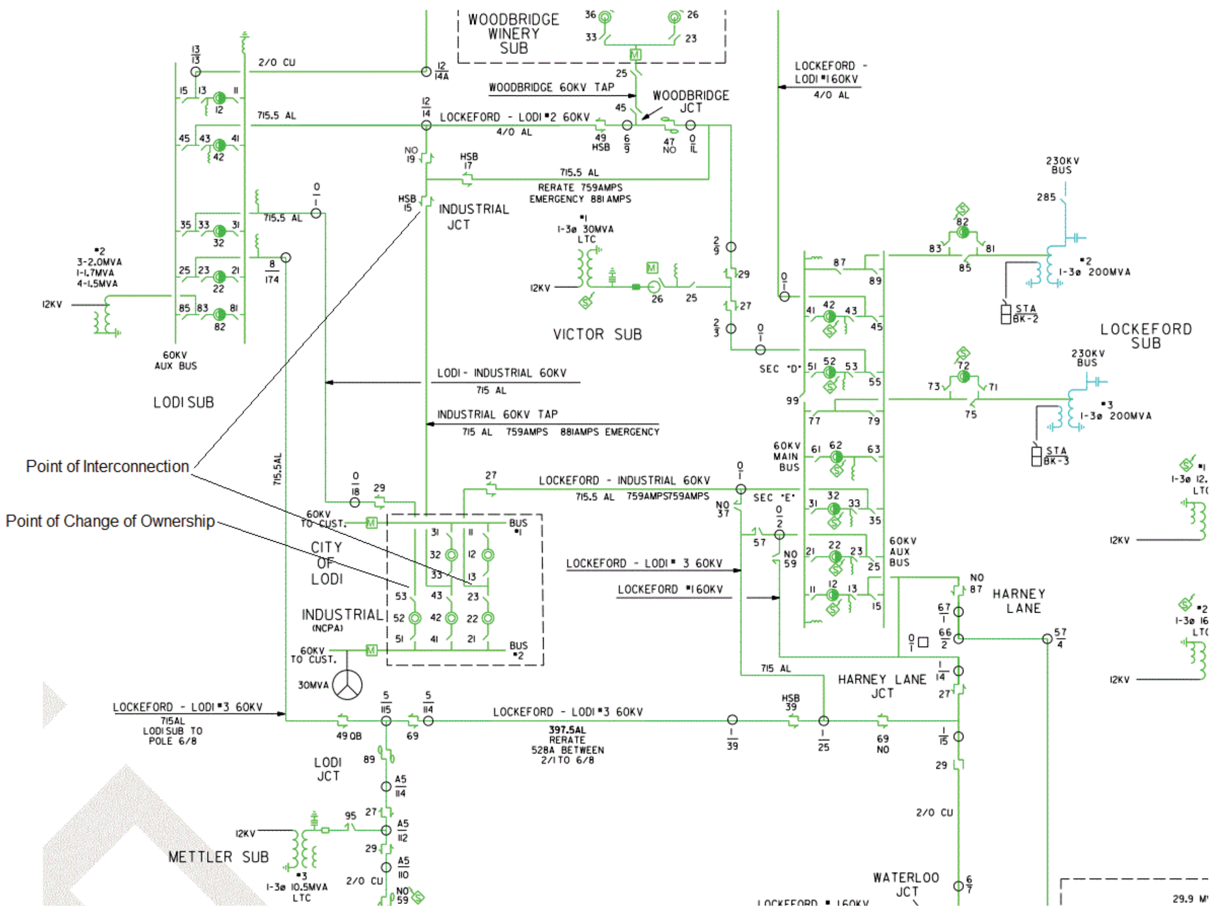
CITY OF HEALDSBURG SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Healdsburg's ("Healdsburg") Interconnection Facilities at the Points of Interconnection that identifies the owner of such Interconnection Facilities.



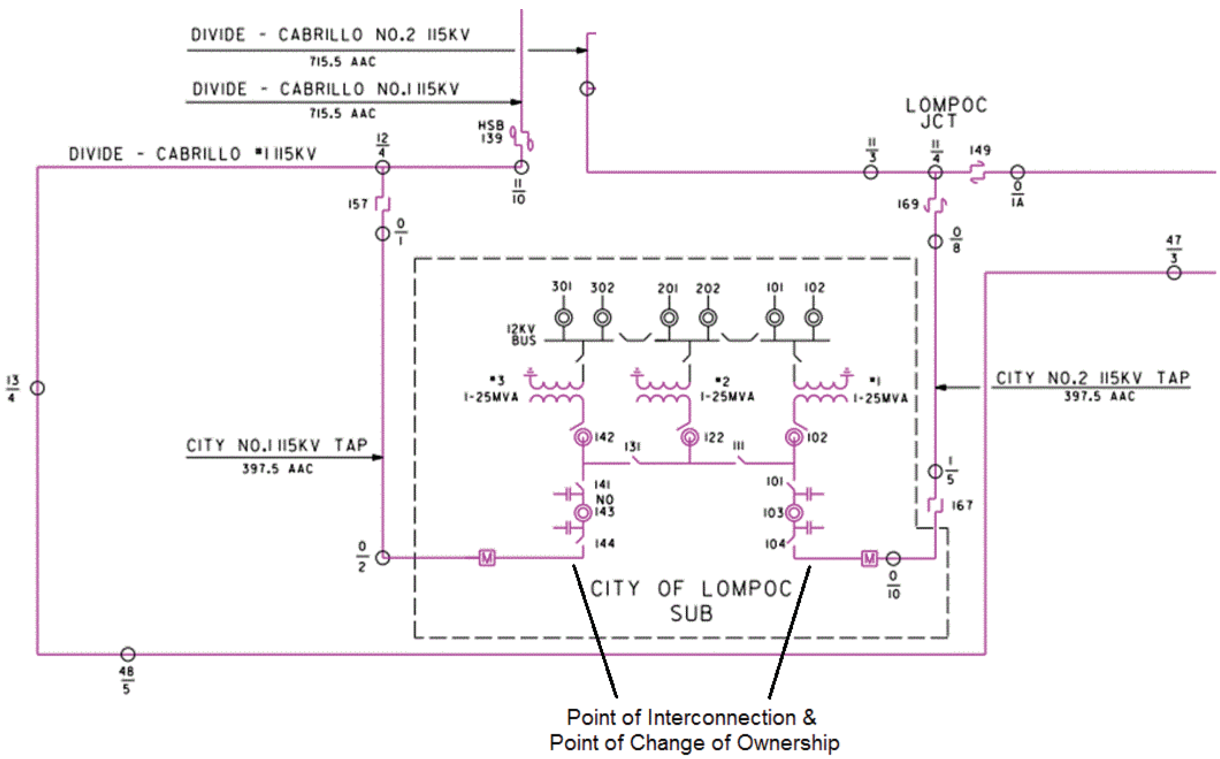
CITY OF LODI SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Lodi's ("Lodi") Interconnection Facilities at the Points of Interconnection that identifies the owner of such Interconnection Facilities.



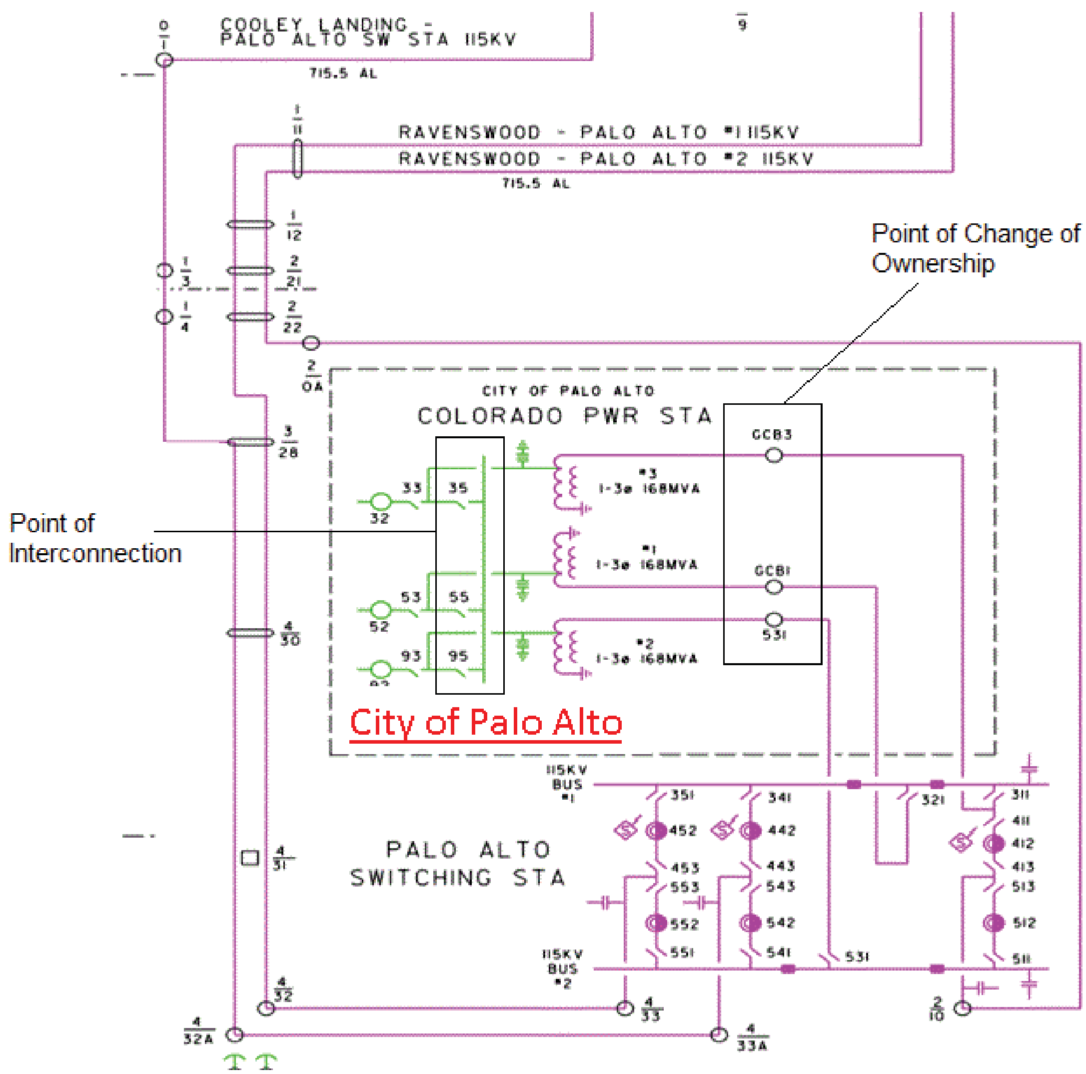
CITY OF LOMPOC SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Lompoc's ("Lompoc") Interconnection Facilities at the Points of Interconnection that identifies the owner of such Interconnection Facilities.



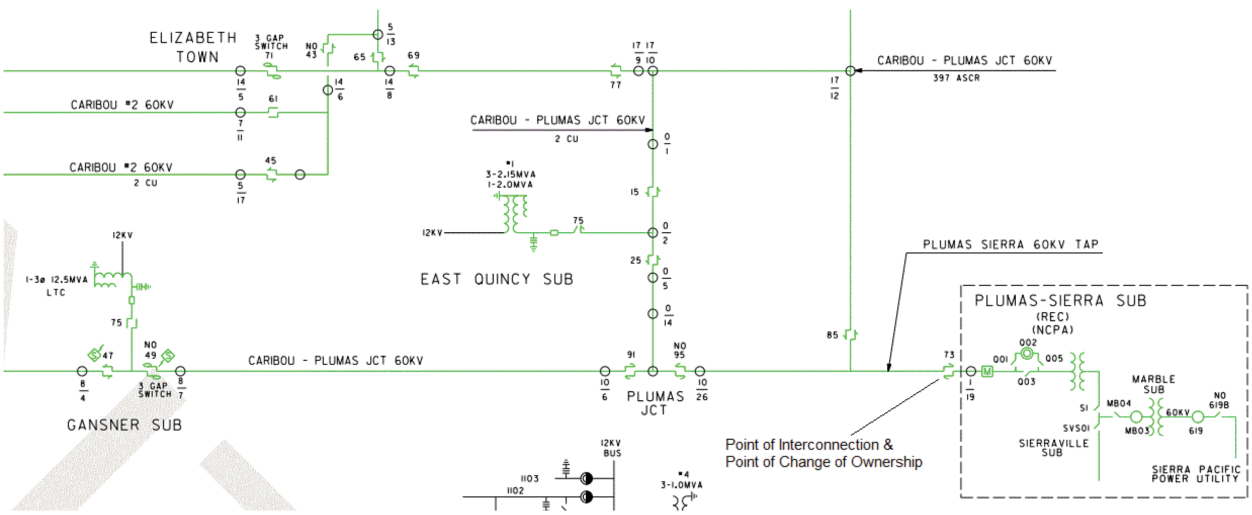
CITY OF PALO ALTO SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Palo Alto's ("Palo Alto") Interconnection Facilities at the Points of Interconnection that identifies the owner of such Interconnection Facilities.



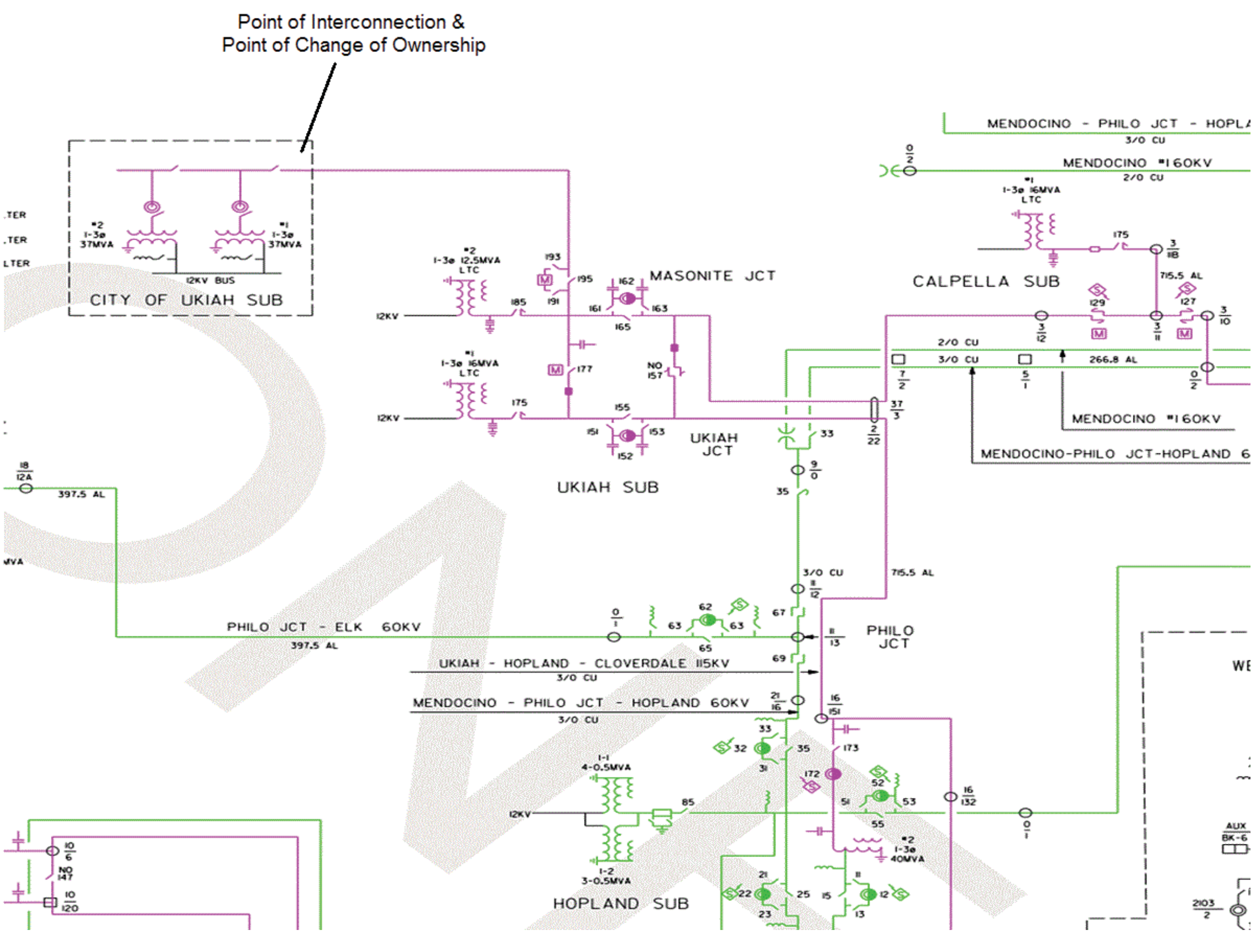
PLUMAS SIERRA RURAL ELECTRIC COOPERATIVE SCHEMATIC FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the Plumas Sierra Rural Electric Cooperative's ("Plumas") Interconnection Facilities at the Point of Interconnection that identifies the owner of such Interconnection Facilities.



CITY OF UKIAH SCHEMATIC
FACILITIES AT POINT OF INTERCONNECTION AND OWNERSHIP

The following is a single-line diagram of the City of Ukiah's ("Ukiah") Interconnection Facilities at the Point of Interconnection that identifies the owner of such Interconnection Facilities.



APPENDIX B
DISPUTE RESOLUTION AND ARBITRATION

B.1 NEGOTIATION AND MEDIATION

As provided in Section 22, the Parties agree to seek settlement of all disputes arising under this Agreement by good faith negotiation before resorting to other methods of dispute resolution. In the event that negotiations have failed, but before initiating arbitration proceedings under this Appendix B, the Parties may by mutual assent decide to seek resolution of a dispute through mediation. If this occurs, the Parties shall meet and confer to establish an appropriate timetable for mediation, to pick a mediator, and to decide on any other terms and conditions that will govern the mediation.

B.2 TECHNICAL ARBITRATION

The Parties agree to seek expedited resolution of arbitrable disputes arising under this Agreement that are technical in nature. Technical disputes may include, without limitation, disputes centered on engineering issues involving technical planning studies, the need for and Cost of Upgrade Facilities, and the Interconnection Capacity of a Point of Interconnection. Such technical issues may be resolved through expert application of established technical knowledge and by reference to Good Utility Practice and industry standards.

The Party initiating arbitration pursuant to Section B.3 below shall indicate in its notice to the other Party whether it regards the dispute to be technical in nature. If the Parties agree that a dispute is technical in nature, then the Parties shall meet and confer to develop an appropriate timetable and process for expedited resolution of the dispute by a neutral expert, or “technical arbitrator”. If the Parties cannot agree that a dispute is technical in nature, or if they cannot agree on a neutral arbitrator, then the Parties may submit the dispute to arbitration under the procedures set forth in Appendix B, Section 3 below.

B.3 ARBITRATION

B.3.1 Notices And Selection Of Arbitrators

In the event that a dispute is subject to arbitration under Section 22, the aggrieved Party or Parties shall initiate arbitration by sending written notice to the other Party or Parties. Such notice shall identify the name and address of an impartial person to act as an arbitrator. If any Party takes the position that the dispute is not arbitrable, any Party may take the dispute to FERC for resolution. Within ten (10) business days after receipt of such notice, the other Party or Parties shall, if they agree that the decision is properly arbitrable, give a similar written notice stating the name and address of the second impartial person to act as an arbitrator. Each Party (or aligned group of Parties) shall then submit to the two named arbitrators a list of the names and addresses of at least three persons for use by the two named arbitrators in the selection of the third arbitrator. If the same name or names appear on both lists, the two named arbitrators shall appoint one of the persons named on both lists as the third arbitrator. If no name appears on both lists, the two named arbitrators shall select a third arbitrator from either list or independently of either list. Each arbitrator selected under these procedures shall be a person experienced in the construction, design, operation or regulation of electric power transmission facilities, as applicable to the issue(s) in dispute. If NCPA and any one or more of the NCPA Members Customers are acting jointly or have aligned positions regarding the subject under arbitration, NCPA and the NCPA Member Customers who are acting jointly/have aligned positions will be treated as a single Party for the purposes of selection of an arbitrator.

B.4 PROCEDURES

Within fifteen (15) business days after the appointment of the third arbitrator, or on such other date to which the parties may agree, the arbitrators shall meet to determine the procedures that are to be followed in conducting the arbitration, including, without limitation, such procedures as may be necessary for the taking of discovery, giving testimony and submission of written arguments and briefs to the arbitrators. Unless otherwise mutually agreed by the parties, the arbitrators shall determine such procedures based upon the purpose of the Parties in conducting an arbitration under Section 22 of the Agreement, specifically, the purpose of utilizing the least burdensome, least expensive and most expeditious dispute resolution procedures consistent with providing each Party with a fair and reasonable opportunity to be heard. If the arbitrators are unable unanimously to agree to the procedures to be used in the arbitration, the arbitration shall be governed by the Commercial Arbitration Rules of the American Arbitration Association.

B.5 HEARING AND DECISION

After giving the Parties due notice of hearing and a reasonable opportunity to be heard, the arbitrators shall hear the dispute(s) submitted for arbitration and shall render their decision within ninety (90) calendar days after appointment of the third arbitrator or such other date selected upon the mutual agreement of the Parties. The arbitrators' decision shall be made in writing and signed by any two of the three arbitrators. The decision shall be final and binding upon the parties subject to rights to appeal the decision to FERC. Judgment may be entered on the decision in any court of competent jurisdiction upon the application of any Party.

B.6 EXPENSES

Each Party shall bear its own Costs and the Costs and expenses of the arbitrators shall be borne equally by the Parties. If the NCPA Parties are acting jointly regarding the subject under arbitration, the NCPA Parties will be treated as a single Party for the purpose of allocating Costs and expenses of the arbitrators.

APPENDIX C
UPGRADE FACILITIES

C.1 UPGRADE FACILITIES

At least 60 calendar days prior to the date on which NCPA or an NCPA Member Customer is to commence payment of any Cost as a result of construction of an Upgrade Facility, PG&E shall determine and provide to NCPA and the NCPA Member Customer, if applicable: (i) an estimate of all Cost, broken down by major activities, which PG&E expects to incur; and (ii) a schedule indicating the approximate dates when PG&E expects to pay such Cost for each major activity included in the estimate. PG&E may revise the payment schedule from time to time as appropriate.

C.1.1 If needed, the Affected Parties will enter into a Transmission Facilities Agreement that shall include an estimate and schedule of Cost and payments , and the applicable NCPA Party shall advance such Cost to PG&E pursuant to such schedule or any revisions to it.

C.1.2 The applicable NCPA Party's total payments to PG&E for work performed under this Appendix C, Section 1 shall be for the actual Cost incurred by PG&E. PG&E shall document to the NCPA Party the actual Cost incurred upon completion, and shall refund any amount overpaid by, or request any additional payment from, the NCPA Party, with interest computed as provided in Appendix D, Section D.6 of this Agreement.

C.1.3 Should an NCPA Party seek a ruling from the Internal Revenue Service that its payments under this subsection should be treated as non-taxable contributions-in-aid-of-construction, PG&E shall cooperate reasonably with the NCPA Party in supporting its filing with the Internal Revenue Service.

C.1.4 The NCPA Party shall have the right pursuant to Section 14 of this Agreement to audit the supporting documents upon which PG&E bases its estimate of the Cost of work and actual work performed to be advanced by the NCPA Party pursuant to the Transmission Facilities Agreement, as well as documents that show the actual Cost incurred by PG&E.

C.2 ASSOCIATED FERC FILINGS

If required by FERC or requested by an NCPA Party, PG&E shall file, or at its election may file, with FERC a Transmission Facilities Agreement to document and seek approval of any Cost charged by PG&E to an NCPA Party associated with any facility Modifications, changes, reinforcements or advances contemplated by this Agreement. A NCPA Party shall support this filing by an appropriate submittal to FERC stating its agreement with the charges; provided, that if the Parties are unable to agree on the need or design for an Upgrade Facility or the Cost of an Upgrade Facility or the amount thereof an NCPA Party shall be responsible for, the NCPA Parties may oppose such PG&E filing.

C.3 LIMITATIONS ON RESPONSIBILITY FOR UPGRADE COSTS

C.3.1 No Double Collection

PG&E may not charge an NCPA Party for any Costs associated with Upgrade Facilities that have already been or will be collected through rates paid by PG&E retail or wholesale customers or from a Third Party; provided, that this Section shall not preclude PG&E charging an NCPA Party where refunds are made to those who originally paid for such Costs.

APPENDIX D
BILLING AND PAYMENT

The NCPA Parties shall pay PG&E Costs owed pursuant to this Agreement at:

Pacific Gas and Electric Company
Payment Processing Center
Research Unit / B5A
P.O. Box 770000
San Francisco, CA 94177

PG&E may change the place where payment is made by giving the NCPA Parties notice thereof as provided in Section 31.

PG&E shall pay NCPA or an NCPA Member Customer Costs owed pursuant to this Agreement at a place to be named by NCPA or an NCPA Member Customer.

D.1 PG&E shall prepare and submit bills to an NCPA Party on or after the first business day of each calendar month. The payment of any bill shall be due and must be received by PG&E not later than the 30th calendar day following the day on which NCPA receives the bill. Such date shall be referred to as the "Payment Due Date". If the Payment Due Date falls on a Saturday, Sunday or legal holiday, then payment shall be due the next business day. Such date shall be referred to as the Payment Due Date. A bill shall be deemed delivered on the third business day after the postmarked date unless a copy of the bill is sent by electronic facsimile, in which case it shall be deemed delivered on the same day.

D.2 If charges under this Agreement cannot be determined accurately for preparing a bill, PG&E may use its best estimates in preparing the bill and such estimated bill shall be paid by the NCPA Parties. Any estimated charges shall be labeled as such and PG&E shall, upon request, document the basis for the estimate used. Estimated bills shall be prepared and paid in the same manner as other bills under this Agreement.

D.3 If an NCPA Party disputes all or any portion of a bill submitted to it by PG&E, it nevertheless shall, not later than the Payment Due Date of that bill, pay the bill in full. A dispute between a Party and any Third Party shall not be a proper basis for withholding payment. Payments to PG&E of the NCPA Party's obligations arising under this Agreement are not subject to any reduction, whether by offset, payments into escrow, or otherwise, except for routine adjustments or corrections as may be agreed to by the Parties or as expressly provided in this Agreement.

D.4 When final and complete billing information becomes available and a charge is determined accurately or billing errors are identified and corrected, PG&E shall promptly prepare and submit an adjusted bill to an NCPA Party, and any additional payments by an NCPA Party shall be made in accordance with the provisions of this Appendix D. Refunds by PG&E shall be paid to the affected NCPA Party not later than thirty (30) calendar days after the date of the adjusted bill. All adjustments or corrections of bills under this Agreement shall be subject to the interest provisions of Appendix D, Sections 5 and 6.

D.5 Interest on an additional payment shall accrue from the Payment Due Date of the applicable bill and interest on a refund shall accrue from the date payment of the applicable bill was received by PG&E.

D.6 Any amount due under this Agreement which is not timely paid shall accrue interest from the date prescribed in Appendix D, Section 5 until the date payment is made. The interest amount shall be determined using the interest rate applicable to any amount due during a given month and shall be calculated using the methodology for refunds pursuant to Section 35.19(a) of FERC's Regulations, 18 C.F.R § 35.19(a). This interest rate shall not exceed the maximum interest rate permitted under California law. Interest shall be calculated for the period that the payment is overdue or the period during which the refund is accruing interest.

D.7 As provided in Appendix D, Section 3, if any portion of a bill is disputed, the disputing Party shall pay the full amount, without offset or reduction, by the Payment Due Date, however, a Party can challenge the accuracy of a bill even if no dispute was identified prior to the Party's payment of the bill and such right to dispute a bill shall extend to the end of the statutory period of limitations. In addition, the disputing Party shall, on or before the Payment Due Date, notify PG&E, in writing, of the amount in dispute and the specific basis for the dispute. The Parties shall endeavor to resolve any billing dispute within thirty (30) calendar days of PG&E's receipt of the disputing Party's notice of a dispute (or such extended period as the Parties may establish). If the Parties cannot agree, any Party may initiate dispute resolution pursuant to Section 22.

D.8 If, after a disputing Party has paid the full amount of a disputed bill directly to PG&E, the results of dispute resolution pursuant to Section 22 include a determination that the amount due was different than the amount paid by the disputing Party, a refund by PG&E to the disputing Party shall include interest for the period from the date the disputing Party's overpayment was received by PG&E to the date the refund is paid to the disputing Party. Likewise, an additional payment by the disputing Party to PG&E shall include interest for the period from the original Payment Due Date to the date the disputing Party's additional payment is received by PG&E. Interest paid pursuant to this Appendix D, Section 8 shall be at the rate determined pursuant to Appendix D, Section 6.

D.9 A Party's failure to make any payment on or before the applicable Payment Due Date shall constitute a material breach of this Agreement if that failure is not corrected within seven (7) business days after the other Party delivers written notice to non-paying Party. In such event, the Party not receiving payment shall be entitled to pursue any legal, equitable and regulatory rights and remedies it may have under this Agreement or otherwise.

APPENDIX E
OPERATIONAL COORDINATION

The Parties will perform operational coordination obligations and responsibilities, which consist of but are not limited to the following:

E.1 Maintenance Coordination

The Parties shall coordinate, in conformance with their obligations to the Balancing Authority on an annual basis, any planned maintenance outages of transmission facilities of their respective Electric Systems that may reasonably be expected to have a material impact on another Party's Electric System.

E.2 Underfrequency Load Shedding (UFLS)

Each year after the Planning Coordinator allocates automatic underfrequency load shedding ("UFLS") obligations pursuant to Applicable Requirements, PG&E and each NCPA Member Customer shall coordinate UFLS participation for the twelve (12) month period beginning the following July 1 of that year.

PG&E and each NCPA Member Customer with NCPA's assistance shall coordinate to determine each NCPA Member Customers' total amount of UFLS responsibility, if any, for that twelve month period ("NCPA Member Customer UFLS Share"). Each NCPA Member Customer's NCPA Member Customer UFLS Share shall be calculated by multiplying the NCPA Member Customer's proportionate share (represented as a percentage) of the total historical coincident peak electric load in the PG&E service area, for the prior twelve (12) month period as of the date and time specified by the Planning Coordinator, by the total amount of UFLS requirement allocated by the Planning Coordinator to PG&E, acting as the Transmission Operator. Within thirty days after the Planning Coordinator allocates UFLS obligations, PG&E and each NCPA Member Customer shall coordinate to determine how each NCPA Member Customer shall provide UFLS to meet its NCPA Member Customer UFLS Share requirement. Each NCPA Member Customer shall be responsible for ensuring that it has implemented any necessary changes to its underfrequency relay or other relay equipment as necessary to ensure that it is enabled to provide its NCPA Member Customer UFLS Share by July 1 of each calendar year, pursuant to Applicable Requirements. Each NCPA Member Customer shall be responsible for ensuring that it maintains equipment necessary for the purpose of UFLS, in conformance with Applicable Requirements.

If a NCPA Member Customer fails to meet any requirement of this Section E.2, PG&E reserves the right to take any measure necessary to satisfy the NCPA Member Customer's NCPA Member Customer UFLS Share, including but not limited to, implementing automatic load shedding to shed or interrupt some or all load of the NCPA Member Customer.

If at any time PG&E does not require any (one or more) NCPA Member Customer to meet its NCPA Member Customer UFLS Share requirement, this shall not waive or excuse any NCPA Member Customer's obligation to satisfy its NCPA Member Customer UFLS Share requirement in that year or at any future date. And any action PG&E takes to satisfy any NCPA Member Customer's NCPA Member Customer UFLS Share at any time shall not create a precedent or obligation that PG&E must take the same or a similar measure in the future.

Notwithstanding any provision of this Interconnection Agreement, including Section 26, if a NCPA Member Customer fails to meet any requirements of this Section E.2, and if PG&E is assessed any financial penalties by the CAISO, WECC, NERC, FERC, or any other applicable authority as a result of such failure to meet Applicable Requirements, the applicable NCPA Member Customer shall be responsible for compensating PG&E for the share of the financial penalties directly attributable to the NCPA Member Customer's failure under this Section E.2.

E.3 Manual Load Shedding

The Parties shall maintain equipment for the purpose of manual load shedding programs in coordination with Applicable Requirements and the Balancing Authority as system conditions warrant.

E.4 Load Restoration

The Parties shall, in conformance with Applicable Requirements and their obligations to the Balancing Authority, coordinate the restoration of load following a system disturbance, and agree to do so in coordination with the Balancing Authority when required.

E.5 Reactive Power

As between PG&E and each NCPA Member Customer, both Parties shall maintain reactive power flow on each of their Electric Systems so that the sum of the reactive flows at the transmission Point(s) of Interconnection between PG&E and that NCPA Member Customer is within the power factor band of 0.97 lag and 0.99 lead. Both Parties will normally operate their respective systems to minimize kVar exchange between them. Operating conditions may require larger than normal kVar exchange between both Parties, and any such exchange will be done in accordance with Good Utility Practice and Applicable Requirements.

PG&E Fiber and Relay Upgrade Project

January 12, 2026

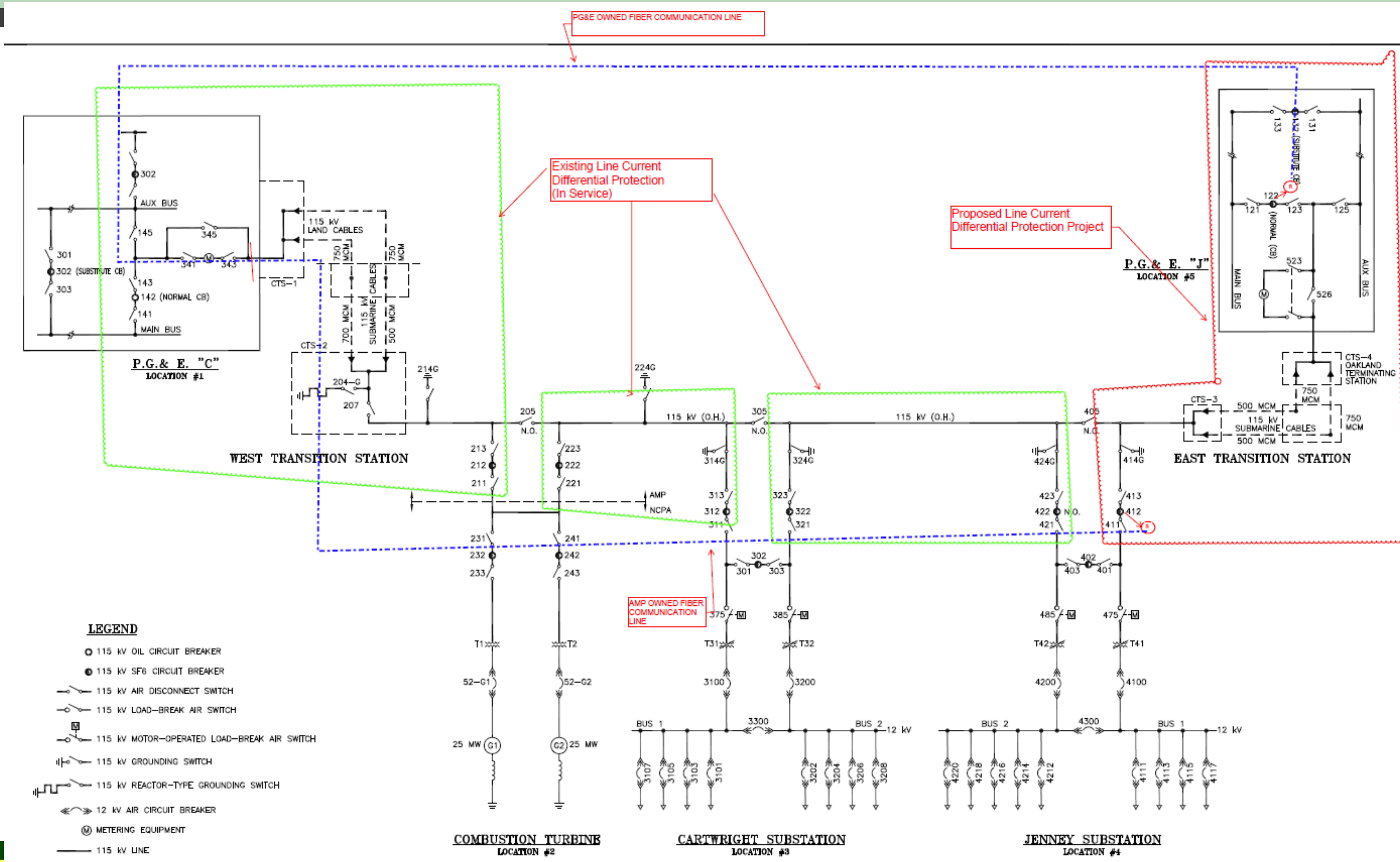
Background

- Line current differential protection is the standard for protecting critical, hard-to-replace infrastructure and reliable service standards.
- AMP lost its AT&T leased copper wire connection and line current differential protection scheme between Station J and Jenney 15 years ago.
- June 2025 – Board approved $7 million towards PG&E fiber and relay upgrade project within the FY26 Capital Budget

Project Justification

1. Project provides a higher level of system reliability, protection, and control of the 115 kV transmission lines between Jenney and Station J.
   - Protects $10 – 20 million submarine 115kV cable
     - Damage to cable would expose AMP to single transmission source for 3 months +.
   - Current distance relays at Station J can overreach and trip Jenney based on a high 12kV fault on AMP's system.
2. Using the PG&E fiber optic communication channel is more economical than installing new direct fiber infrastructures crossing the Oakland-Alameda estuary and Interstate-880.

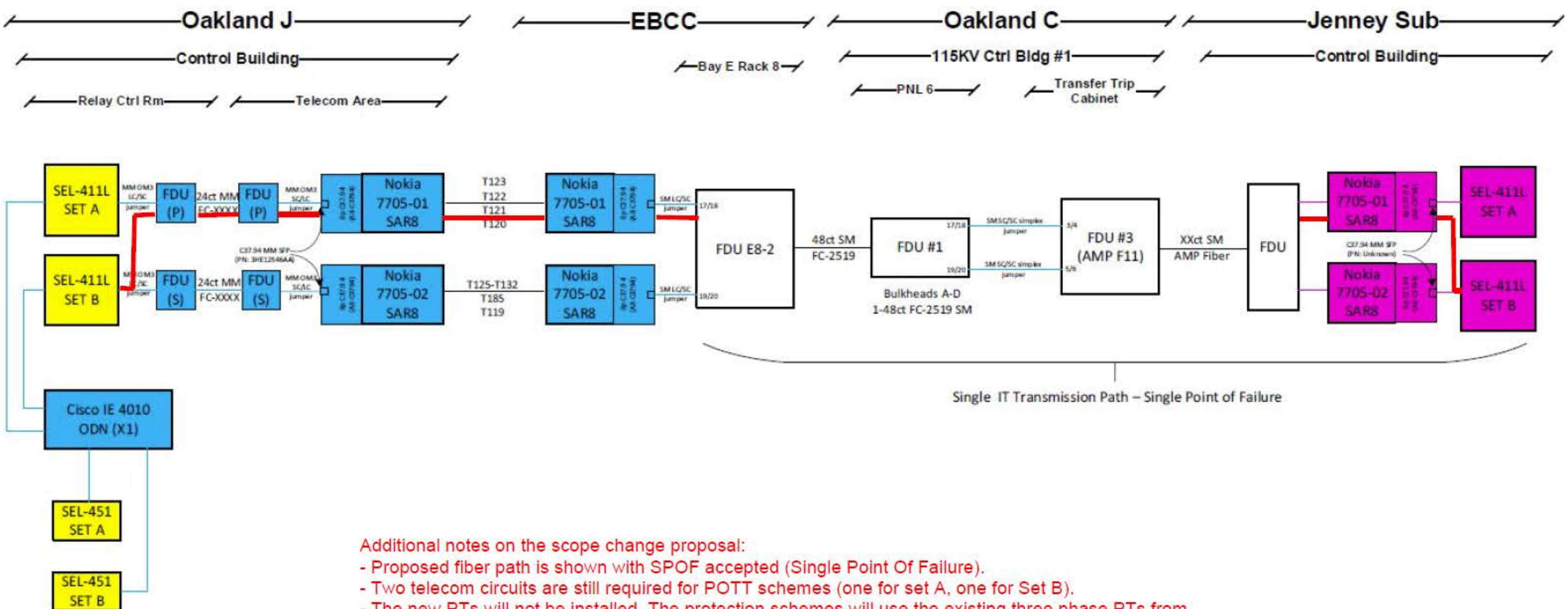
Single-Line



ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

Scope of Work - Diagram

Proposed



Additional notes on the scope change proposal:
- Proposed fiber path is shown with SPOF accepted (Single Point Of Failure).
- Two telecom circuits are still required for POTT schemes (one for set A, one for Set B).
- The new PTs will not be installed. The protection schemes will use the existing three phase PTs from bus side and the existing single A-phase PT on the line side instead.

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

Scope of Work

- PG&E
  - Four relays
  - Five network switches
  - 4 Fiber distribution units
  - Less than 2,000ft of fiber installation
- AMP
  - Two relays
  - Two network switches
  - Relay Consultant

ALAMEDA MUNICIPAL POWER
A Department of the City of Alameda

PG&E Cost Breakdown

Line Item	Unit Cost	Quantity	Total Cost
Labor	$85.00	7,250	$616,250.00
Materials	$175,000.00	1	$175,000.00
Overheads	$1,701,188.00	1	$1,701,188.00
Estimated Total Cost			= $2,492,438.00
Contingency		30%	$747,731.40
Total w/Contingency, Before ITCC			**= $3,240,169.40**
ITCC (Applicable Federal Income Tax Rate)		24%	$777,640.66
TOTAL ESTIMATE			**$4,017,810.06**

Estimated Equivalent of One Time Charge

$19,765.03/mo. (IV.C above) x 12 months × 14.73 (present worth factor) =

$ 3,493,666.70

Special Facilities Financed By	Application Base	Current Percentage Rate	Monthly Charge
AMP	Net Cost of Special Facilities (= A-1 Direct Assignment Facilities below) 1. Estimated cost of transmission facilities installed by PG&E: $3,240,169.40 2. Estimated cost of transmission facilities installed by AMP and deeded to PG&E: $0 Less allowance for existing facilities: -- Estimated net amount: $3,240,169.40	0.61%	$19,765.03/month
PG&E	Existing facilities allocated as Special Facilities	-	-
Total Estimated Monthly Cost-of-Ownership Charge			**$19,765.03/month**

ALAMEDA MUNICIPAL POWER
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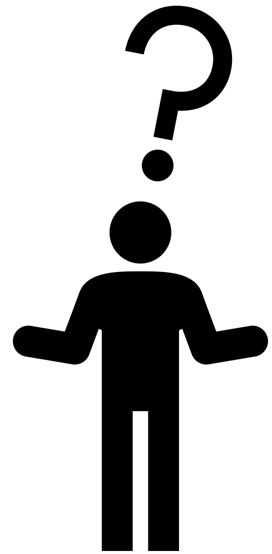
Contingency

- If no contingency is used, final PG&E payments could be as low as $5,778,059.
- Similar to AMP's process for customer connections, PG&E will provide a true-up of actual costs after project completion.

Questions?



ALAMEDA MUNICIPAL POWER

A Department of the City of Alameda

To: Honorable President and
Members of the Public Utilities Board

From: Tim Haines, General Manager

Re: General Manager's Report – January 2026

PUB Highlights

- **Engineering and Operations Update**:
  - Outages:
    - 11/30, 68 customers, 6 hours, equipment
- **Customer Resources Update:**
  - **Community Engagement:**
    - AMP staff joined the Mayor, City Manager, and Base Reuse Economic Development (BRED) on a tour of Anthro Energy's headquarters in Harbor Bay. Anthro Energy is a fast-growing company developing a liquid state battery that is more resilient than solid state batteries and can be flexibly used in a variety of mechanical uses. Their Alameda facility supports research and development, employs 45 people and they expect to double this number in the coming year. The City has nominated Anthro for an East Bay Economic Development Alliance Innovation Award, which they will receive in early 2026.
  - **Community Sponsorships:**
    - AMP sponsored Alameda Christmas Tree Lane, a beloved holiday tradition throughout December that transforms a neighborhood street into a glowing walkway of decorated homes and festive lights. This annual event invites families and visitors to gather, stroll, and celebrate the season together in a safe, joyful setting.
    - The Alameda Yule Midwinter Market on December 13th, on Webster, was sponsored by AMP. This festive community gathering celebrates local artisans, seasonal traditions, and small businesses during the winter months. The market brings neighbors together with handmade goods, food, and cultural activities, creating a warm, welcoming space in the heart of Alameda.
    - AMP was able to sponsor Alameda Post's NewsMatch, a collaborative fundraising campaign that supports independent, nonprofit news organizations. The Alameda Post provides residents a local news source that reports on issues happening in the city such as development and housing, local elections, the environment, and public safety.
  - **Alameda Aquatic Center:**
    - **Microgrid**
      - AMP had proposed installing solar canopies on three sides of the main pool to provide shade and on the pool deck, which will be

geologically improved and less costly than installation in unimproved areas like the parking lot.

- Alameda Recreation and Park Department (ARPD), architectural firm ELS, engineering subcontractor G&B, and AMP's engineering consultant GFT, hereafter referred to as the Design Team, determined that solar canopies could not be installed around the pool due to space constraints and tree shade.
- The Design Team also determined there was no space available inside the facility for the solar equipment, consisting of a transformer, switchboard, alternating current (AC) disconnect, direct current (DC) disconnect, submeter, batteries, and inverter. ELS suggested a different location on the property outside the pool area fencing and on geologically unimproved land. Making the necessary ground improvements to this new location is expected to add $150,000 to AMP's project cost.
- The Design Team concluded that the best available locations for solar canopies are the pool equipment area—a rectangular area parallel and adjacent to the main pool along the Northern property line—and the solar equipment area—a rectangular, fenced area, West of the pool equipment area along the Northern property line.

- **Educational Displays**
  - With a proposed $200,000 budget and a desire to have displays that are relevant and in a conspicuous location, the Design Team has offered up exterior wall space inside the facility and facing the smaller pool. AMP Staff believes this is the best and possibly only location that will work and does not want owned equipment to be outside the facility walls where there is greater potential for vandalism. The Design Team is considering AMP's goals of educating the public in assessing what equipment can go there within the proposed budget.
- **Memorandum of Understanding**
  - The process of drafting an MOU between AMP and ARPD has begun.
- **Building Permit**
  - An Alameda Building Dept official has provided a rough estimate of permit costs at $6,000. This will be refined when permit drawings (in progress) are complete.
- Schedule
  - AMP is on track to be included in ARPD's RFP planned for January 12, 2026, though it is not guaranteed. The fallback plan would be to request an add-on bid after the project is awarded.


AAC

CUSTOMER PROGRAMS & EXPERIENCE

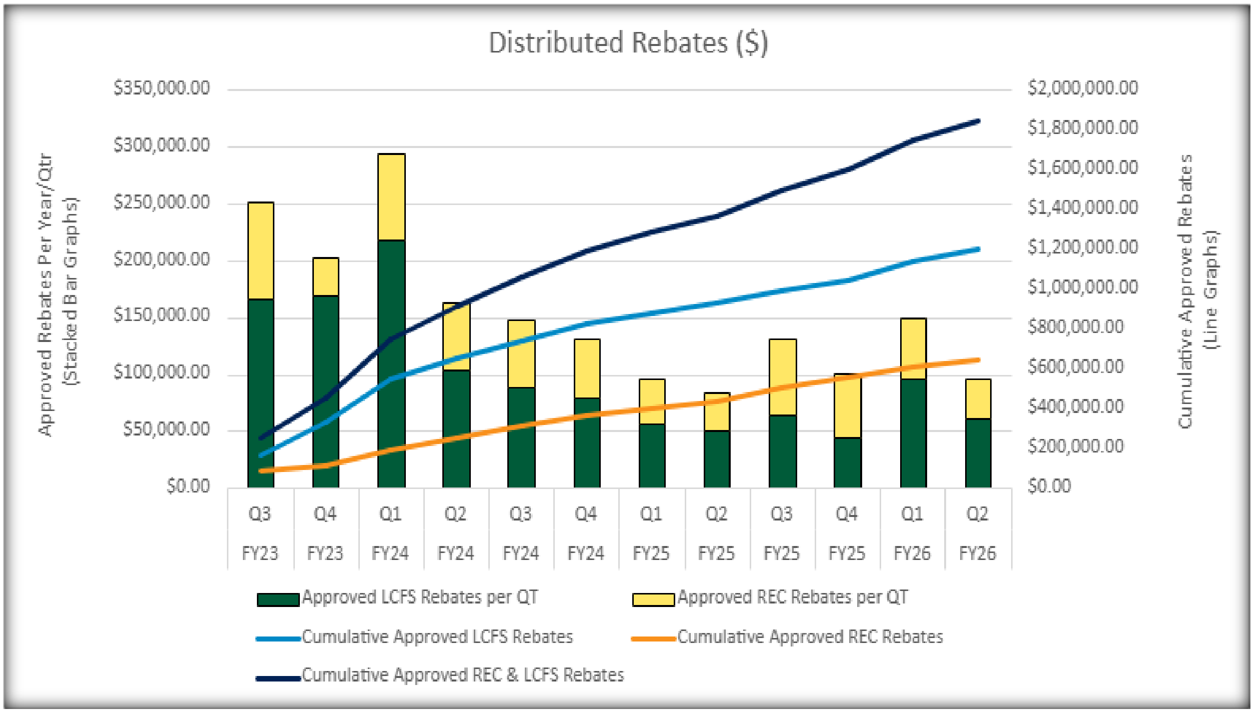


Figure 1: Electrification and Clean Transportation Distributed Rebates

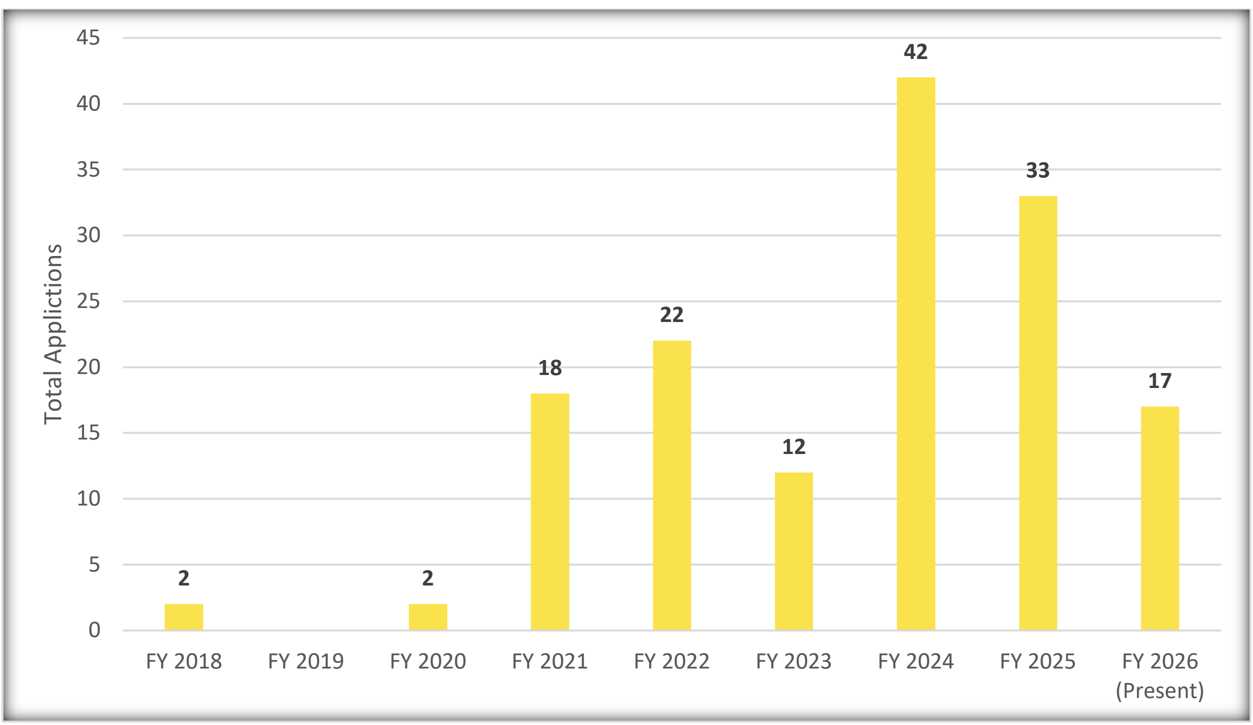


Figure 2: Heat Pump Water Heater Rebate Program

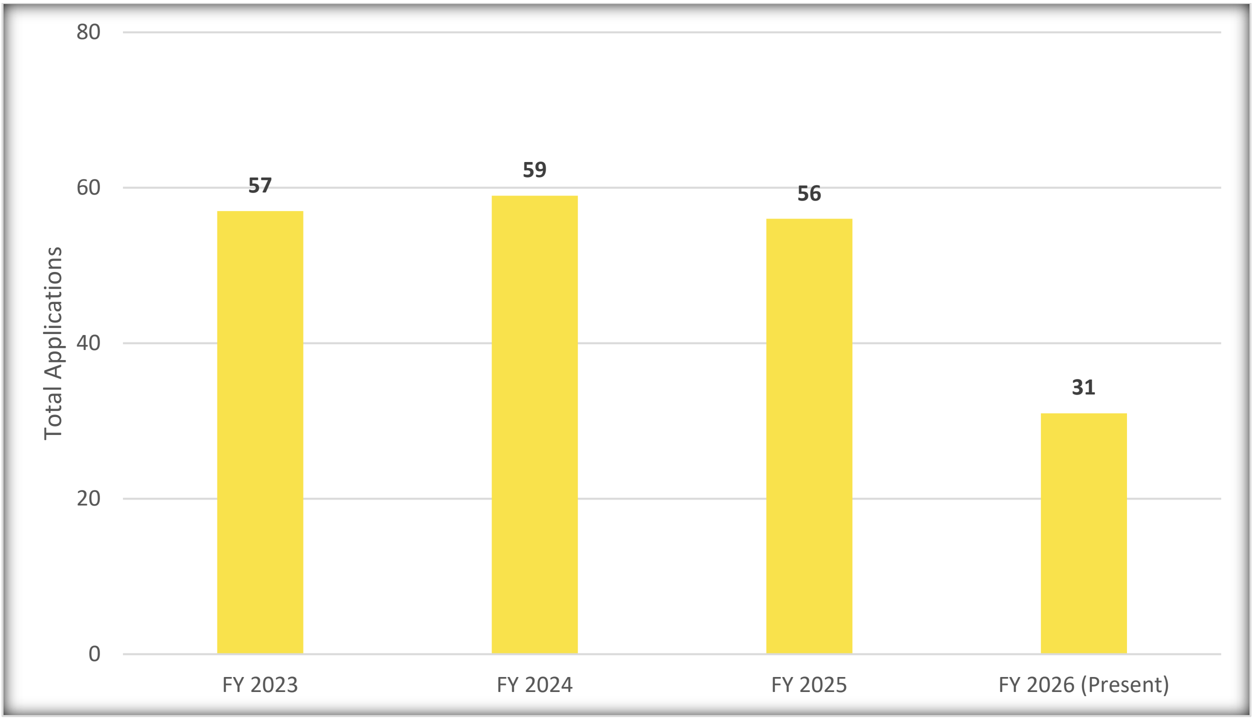


Figure 3: Heat Pump Heating, Ventilation, and Air Conditioning (HVAC) Rebate Program

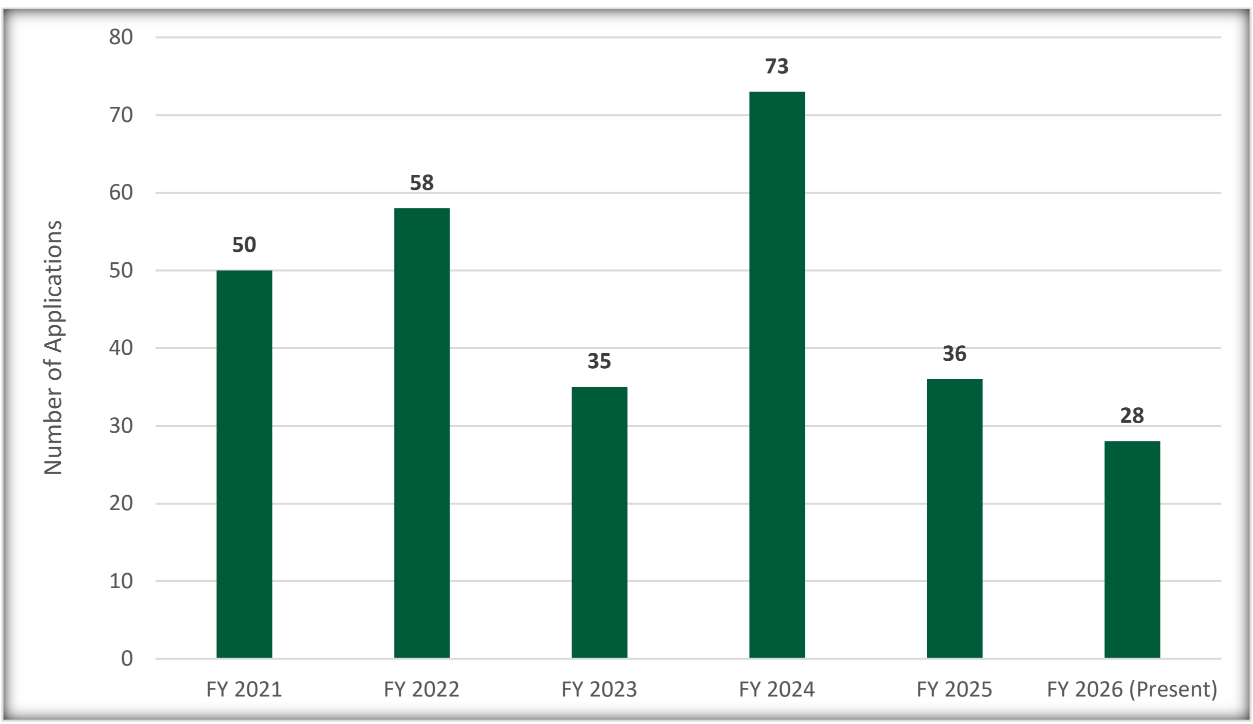


Figure 4: Used Electric Vehicle Rebate Program

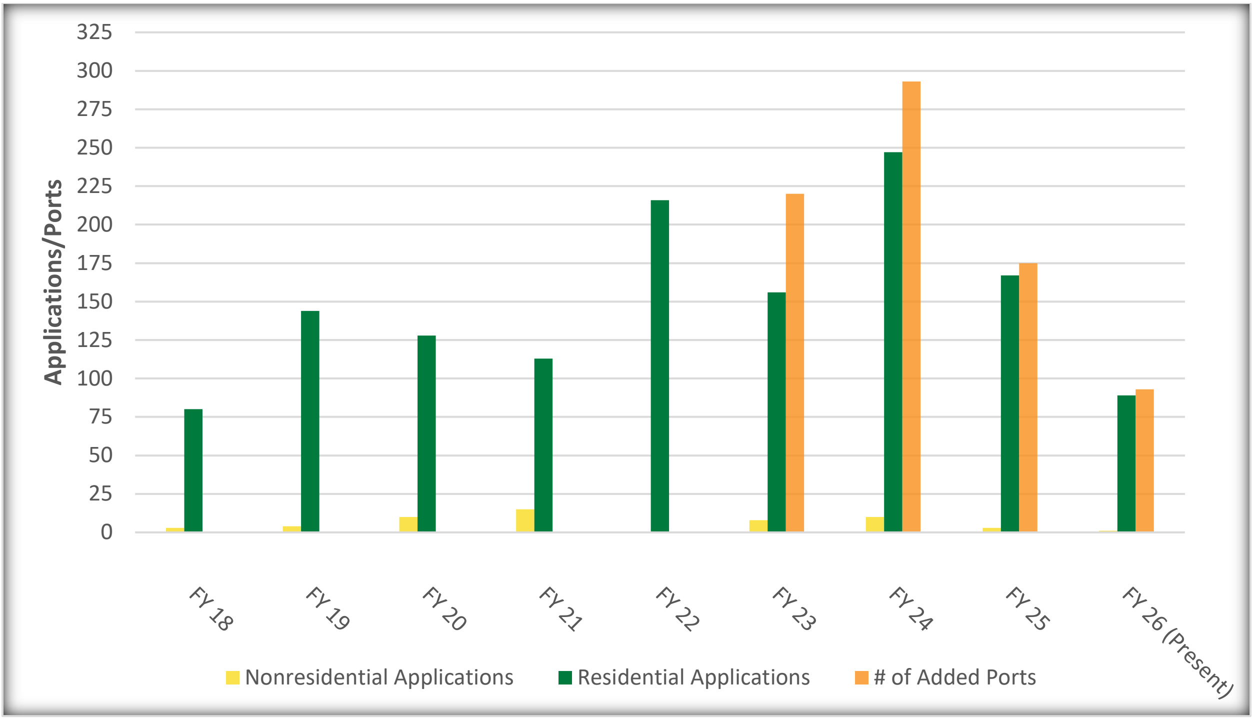


Figure 5: Electric Vehicle Charging Rebates

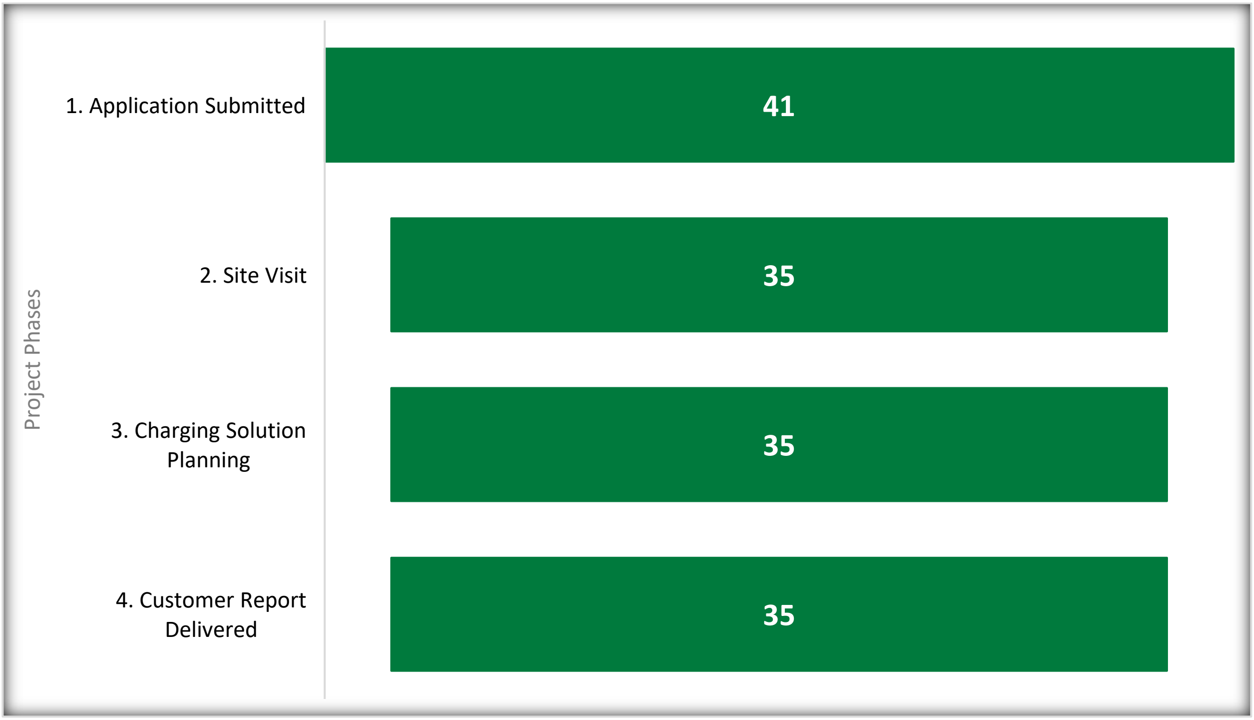


Figure 6: Electric Vehicle (EV) Technical Assistance Program

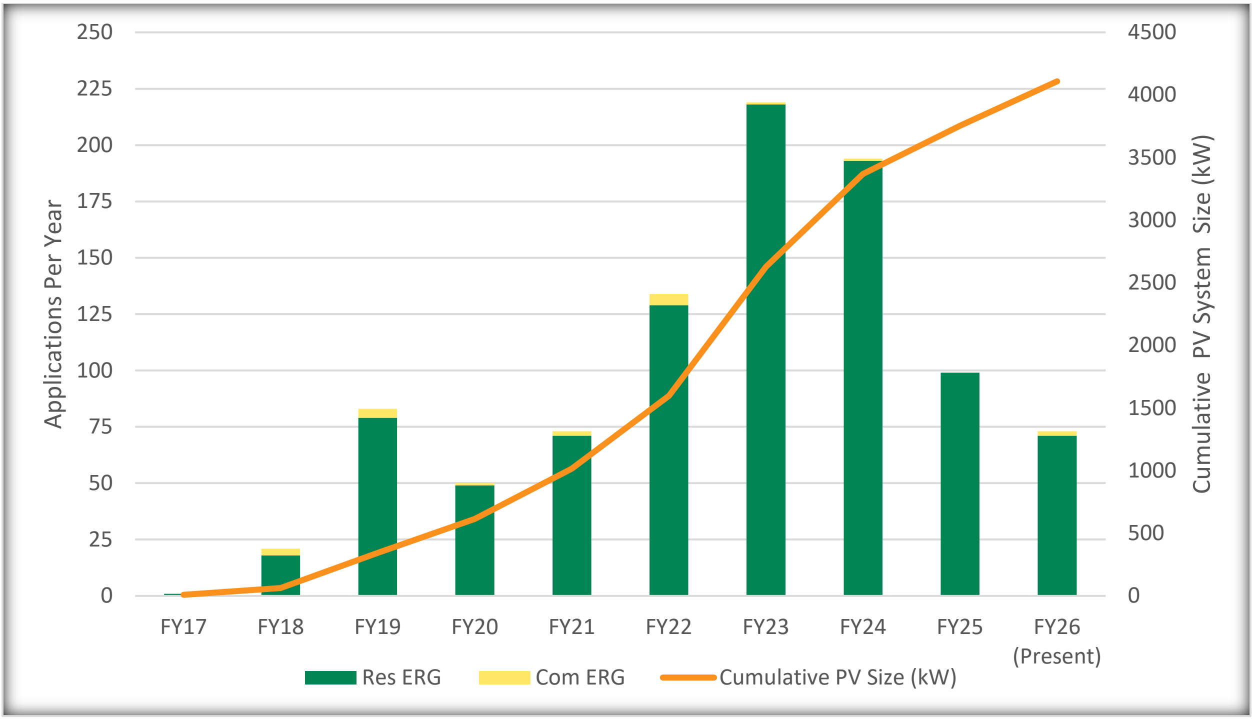


Figure 7: Residential and Commercial Solar Interconnections & Photovoltaic (PV) System Size

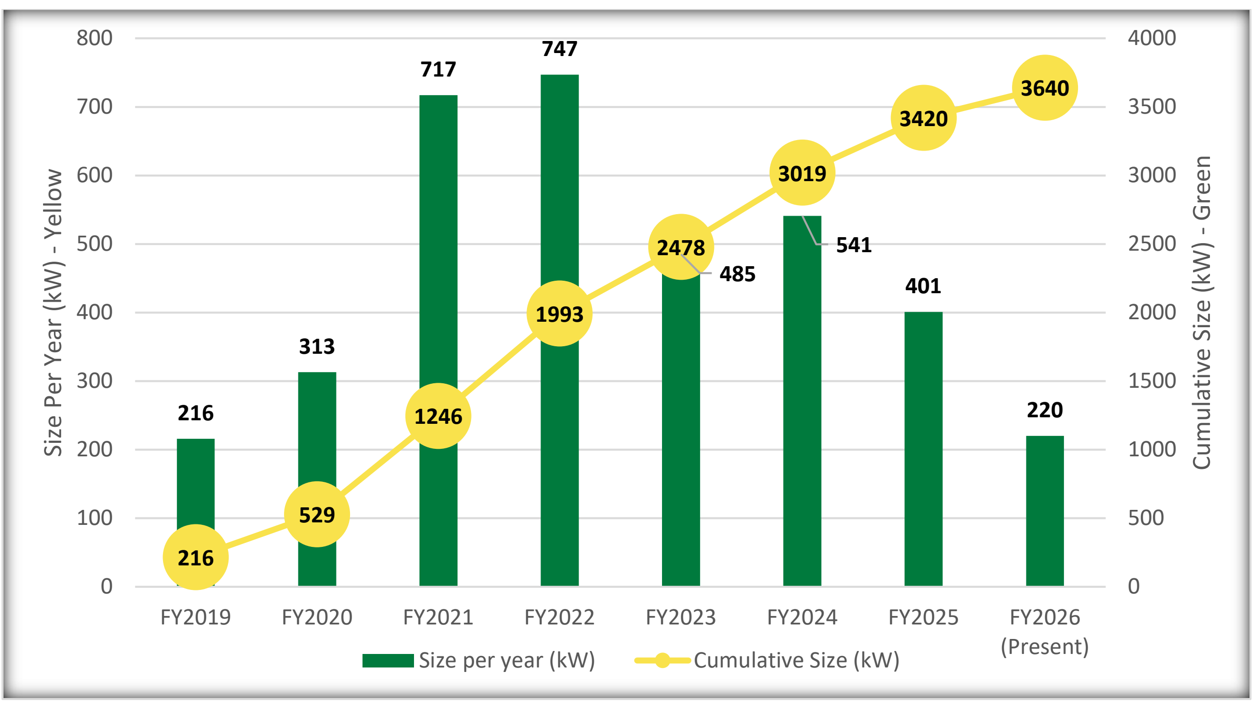


Figure 8: Cumulative Battery Storage

FINANCIALS

Table 1: Monthly and Year to Date Total Operating Revenue and Expense Report as of December 31, 2025

Report Status as of:				
December 31, 2025	Monthly		Annual (FY) To Date	
	Goal	Result	Goal	Result
Total Operating Revenue - Electric (November 2025)	7,311,407	6,985,875	36,884,655	33,866,191
Total Operating Expense - Electric (November 2025)	7,158,590	4,683,290	31,224,521	21,505,724
Note: Shaded areas indicate the data is displayed on the accompanying graphs				

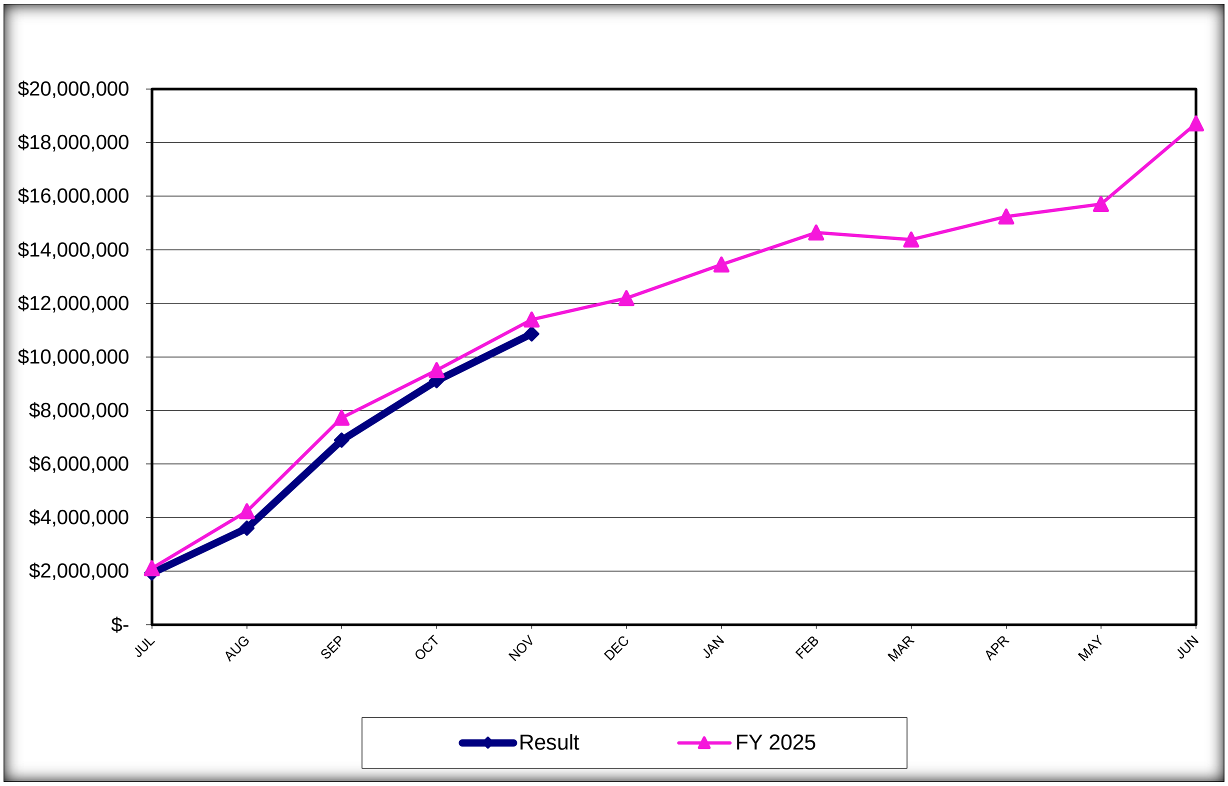


Figure 9: Fiscal Year 2026 Cumulative Net Income – Electric

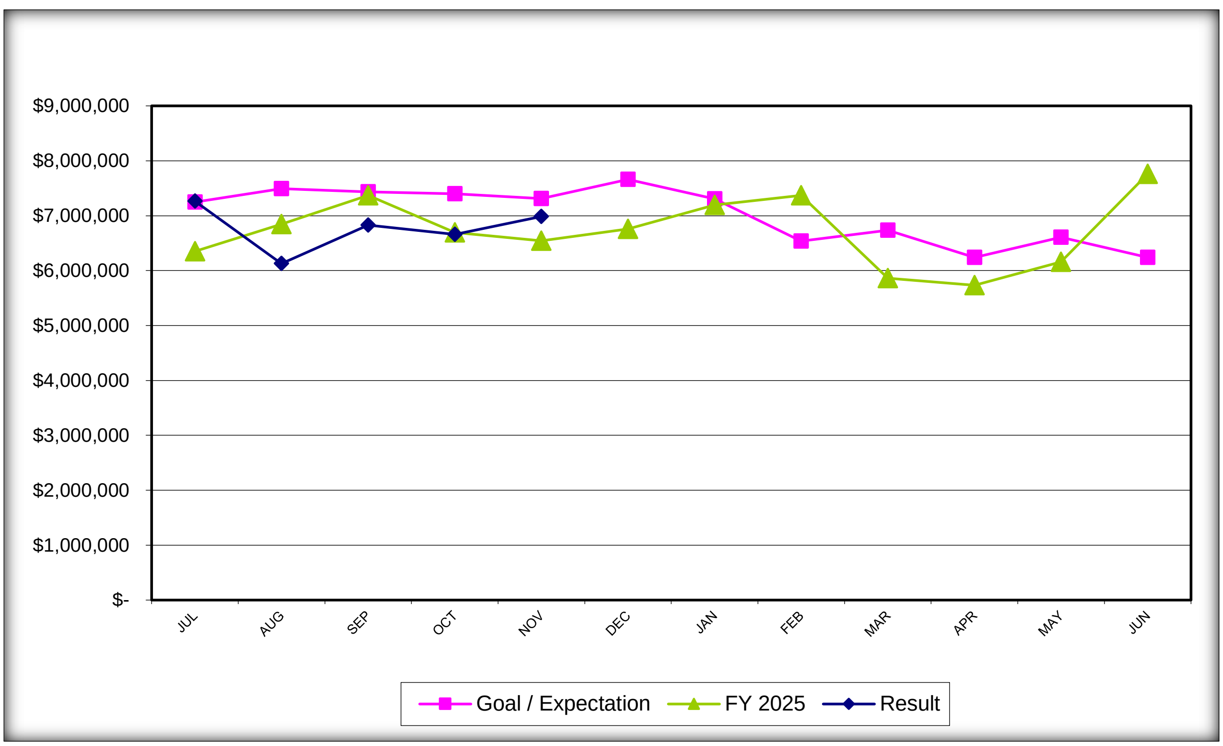


Figure 10: Fiscal Year 2026 Monthly Operating Revenue – Electric

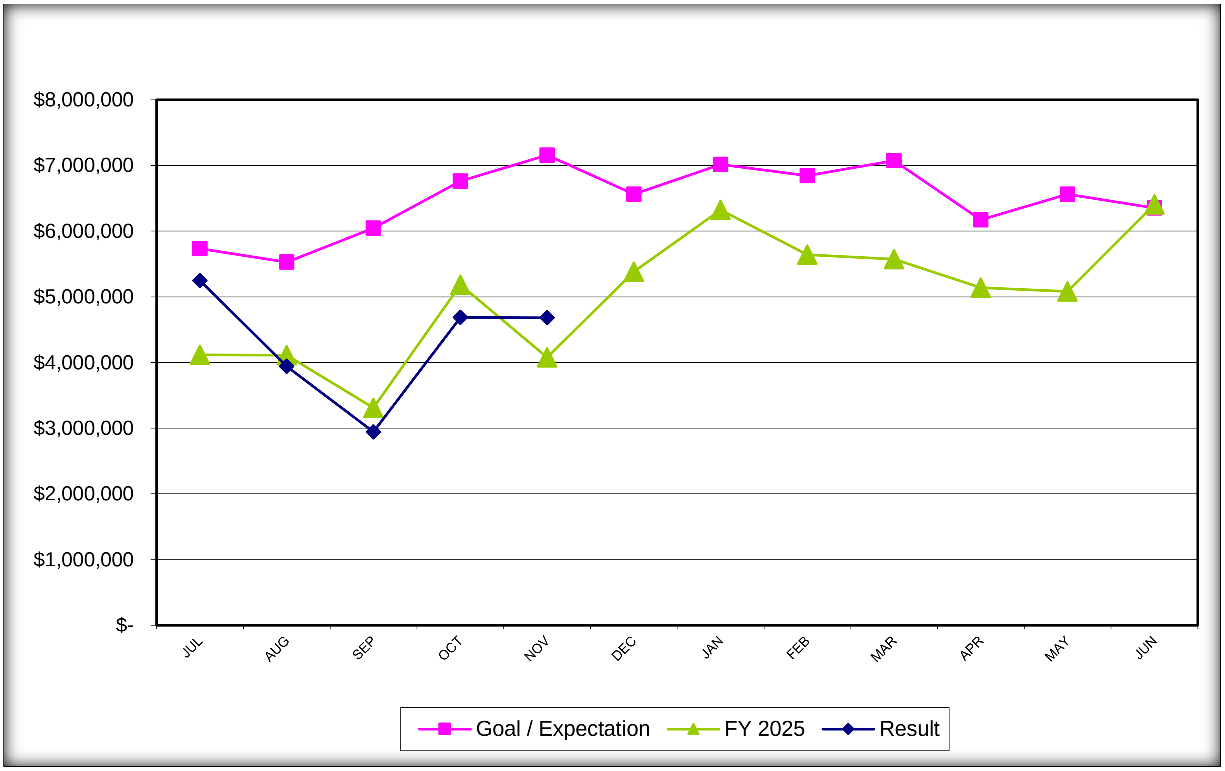


Figure 11: Fiscal Year 2026 Monthly Operating Expense – Electric

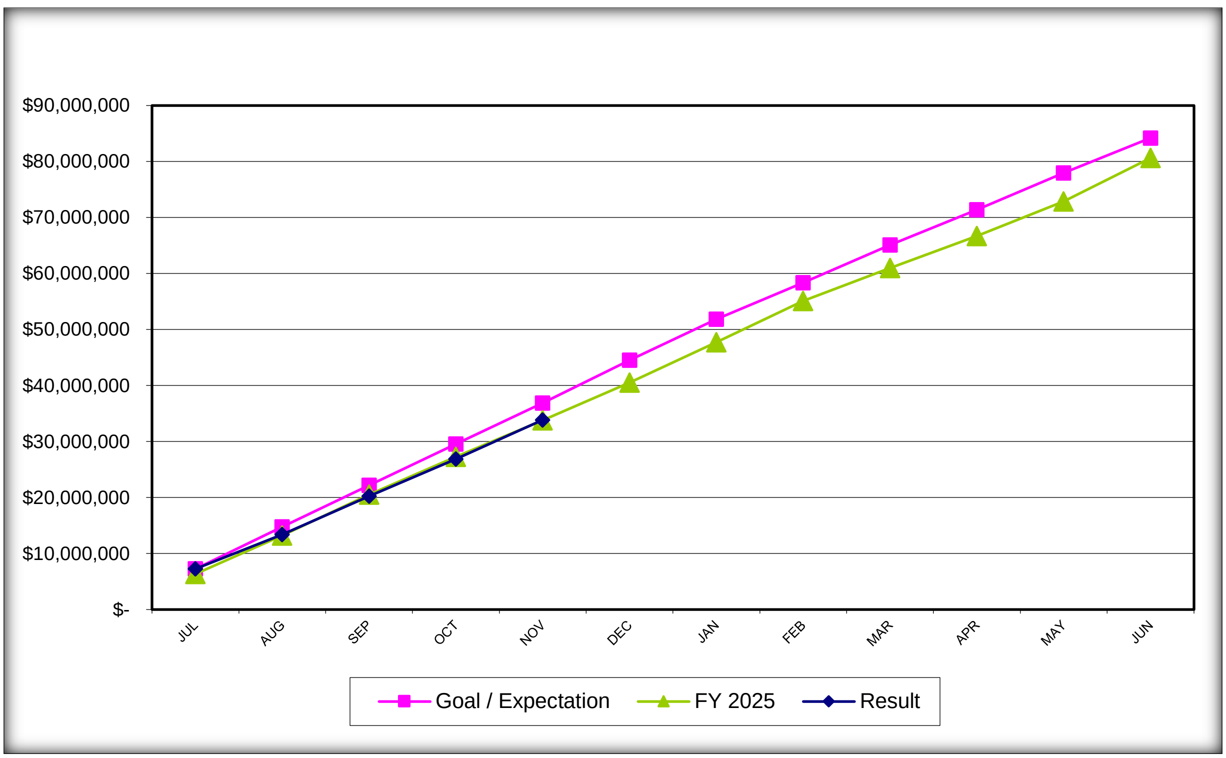


Figure 12: Fiscal Year 2026 Cumulative Operating Revenue – Electric

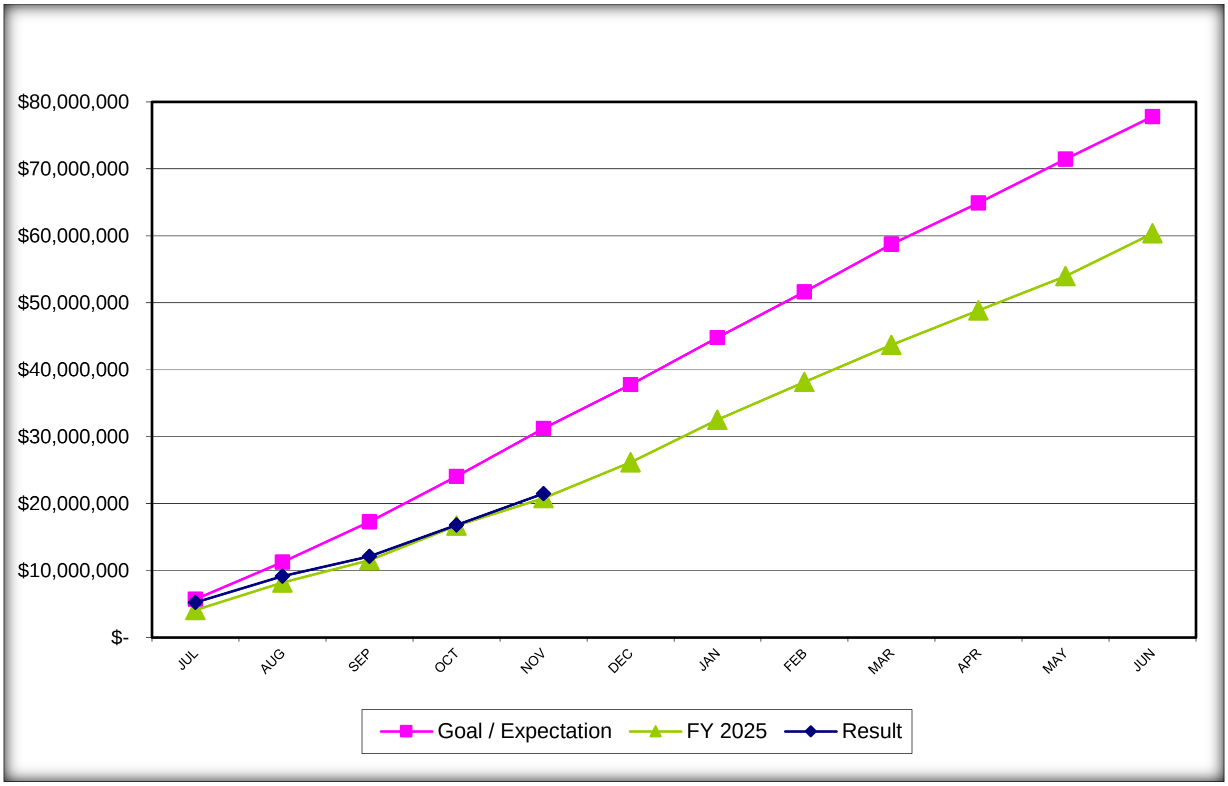


Figure 13: Fiscal Year 2026 Cumulative Operating Expense – Electric

OPERATIONAL STATISTICS

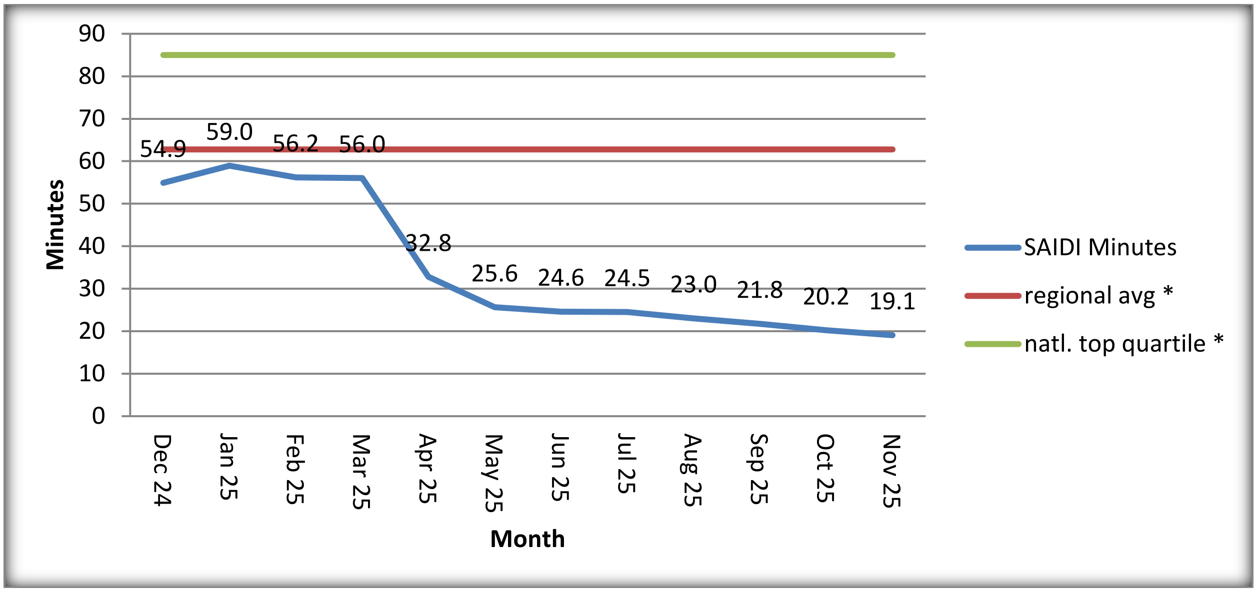


Figure 14: Rolling 12-Month System Average Interruption Duration Index (SAIDI)

*Based on Benchmark study of APPA Region 6

SAIDI= $\dfrac{\text{Sum of customer-minutes off for all interruptions}}{\text{Total number of customers served}}$

System Average Interruption Duration Index (SAIDI):
SAIDI is defined as the average duration of interruptions for customers served during a specified time period. Similar to CAIDI, but the number of customers served instead of affected is used. The unit is minutes. A common usage of SAIDI is "If all customers were without power the same amount of time, they would have been out for _____ minutes.

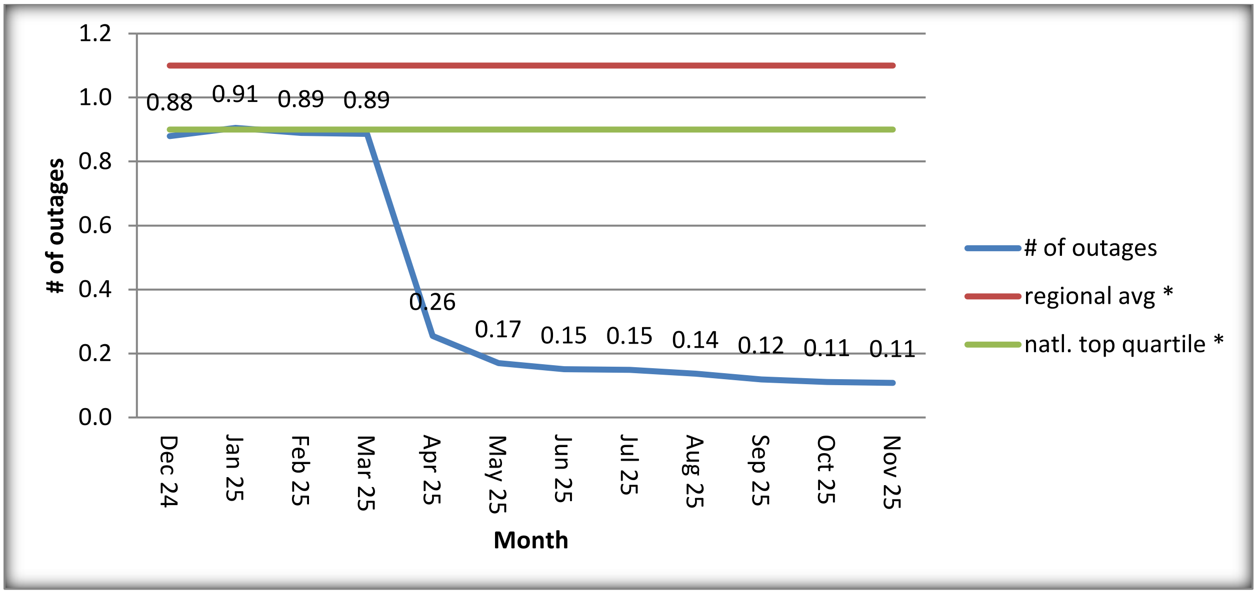


Figure 15: Rolling 12-Month System Average Interruption Frequency Index (SAIFI)

*Based on Benchmark study of Western Regional Utilities

SAIFI= $\dfrac{\text{Total \# of customers affected by interruptions}}{\text{Total number of customers served}}$

System Average Interruption Frequency Index (SAIFI):
SAIFI describes the average number of times a customer experiences a sustained interruption during a specified time period. The unit for SAIFI is 'interruptions per customer'. A common usage of SAIDI is "On average, customers experienced _____ interruptions".

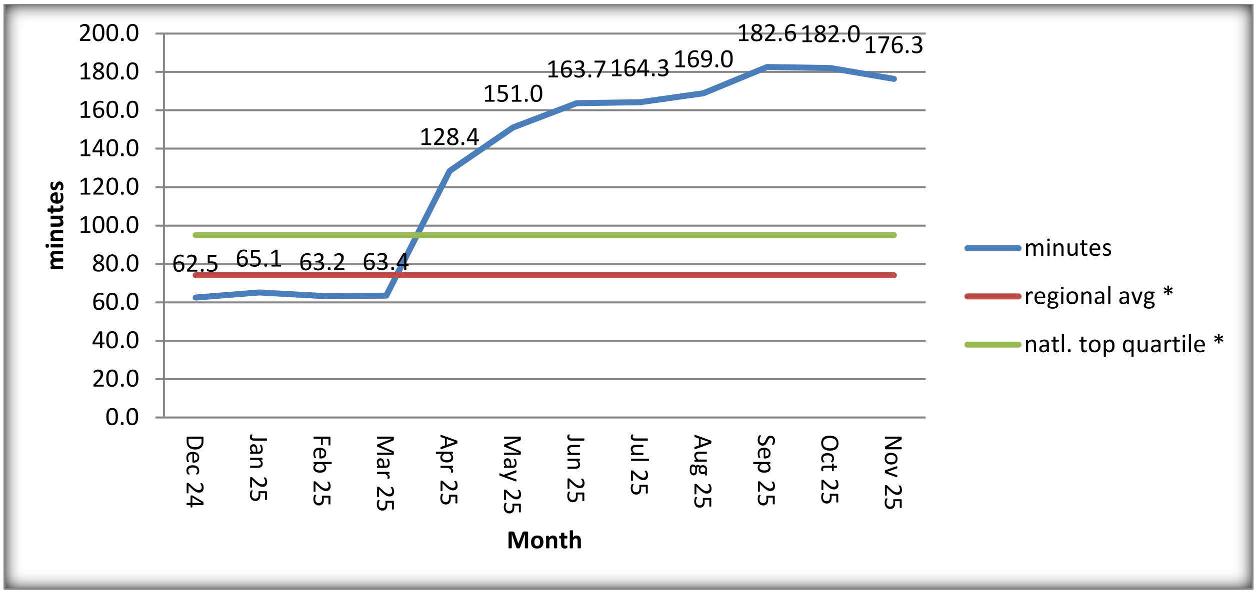


Figure 16: Rolling 12-Month Customer Average Interruption Duration Index (CAIDI)

*Based on Benchmark study of Western Regional Utilities

$$\text{CAIDI} = \frac{\text{Sum of customer-minutes off for all sustained interruptions}}{\text{Total \# of customers affected by the sustained interruptions}}$$

Customer Average Interruption Duration Index - CAIDI
CAIDI is the weighted average length of an interruption for customers affected during a specified time period. The unit of CAIDI is minutes. A common usage of CAIDI is "The average customer that experienced an outage is out for _____ minutes.

Human Resources Progress & Augmentation

Notable steps that have been taken

- Working with a Third Party to:
  - ✓ Finalize updates to 10 position descriptions
  - ✓ Expect to begin Salary Survey of all AMP staff in January (as agreed to in the Labor Agreements)

AMP Vacancy Report (Jan)

Division	Total Positions	Filled	Open
General Manager	3	0	0
Engineering & Operations	45	1	4
Administration	27	2	1
Information Technology	7	0	1
Customer & Energy Resources	13	0	1

- ❑ 3 Open positions were filled in last month
- ❑ 2 Open positions have applications closed and/or hiring underway
- ❑ 3 Open positions are being recruited
- ❑ 1 Open position is being temporarily filled and/or evaluated for upgrade
- ❑ 1 Open position is expected to begin recruitment in Dec

Alameda Municipal Power
A Department of the City of Alameda