DOCKETED	
Docket Number:	18-IRP-01
Project Title:	Integrated Resource Plan
TN #:	253565
Document Title:	City of Burbank, Water and Power IRP Report Part 6 Page 3-63 to 3-100
Description:	The Burbank IRP file was too large, so it had to be separated into multiple parts. This is "Part 6."
Filer:	Mandip K Samra
Organization:	City of Burbank
Submitter Role:	Applicant
Submission Date:	12/7/2023 8:56:42 PM
Docketed Date:	12/8/2023

renewable energy generation and electric transmission resources to the growth of electric demand in Burbank. As a result, the IRP is treated as living document and will be regularly reviewed and updated. Future revisions to the IRP will incorporate changes to energy market conditions, environmental and energy policies, and the results of actions taken by BWP in the interim.

3.2.2.1 Demand

BWP serves the electricity needs of Burbank. In utility terms, these needs are called "demand." Managing and forecasting Burbank's demand is necessary to ensure that electricity can be generated or purchased at low prices and that sufficient supplies of electricity are available to meet the needs of BWP's customers. A full description of the method by which demand was forecast for this IRP analysis is provided in Section 3.5 below.

3.2.2.2 Natural Gas Prices

The natural gas prices used within the Burbank PLEXOS model are built from two major data sources: market quotes and the natural gas price forecast published as a part of the IEPR 2023 Preliminary Electric Generation Price Model.[23]

In the short-term, the natural gas prices are developed as a blend of actual market quotes received by BWP and forward prices based on S&P Global IQ data. Natural gas prices and, in general commodity prices, have been high over the past couple of years primarily due to global supply constraints and disruptions especially in Europe due to the loss of Russian natural gas imports. US exposure to global natural gas markets has also increased mainly due to an increase in domestic liquified natural gas (LNG) export capabilities. However, in 2023, some of these supply pressures have eased because of warmer than expected weather, improved energy efficiency, and reduced industrial activity that has put downward pressure on global natural gas demand.

In the long-term, Black & Veatch projects natural gas prices in US to continue declining over the next few years as it transitions to the fundamental forecast from the IEPR, primarily due to an increase in natural gas production from an increase in drilling activity and overall strength in US natural gas resources in the Permian basin (West Texas) and the Marcellus/Utica shale area (Pennsylvania, Ohio, and West Virginia).

In April 2023, the CEC published its 2023 IEPR Preliminary Electric Generation Model, where the monthly natural gas price forecast was updated and extended to 2050. A Base Case and two sensitivity cases – one for high gas supply, one for low gas supply – were included in this model update. Figure 3-2 demonstrates the forecasted curves of the three IEPR cases in 2023 real dollars. In this IRP, it is assumed the existing price premiums diminish over time and eventually disappear in 2032, 5 years after the current market quotes end. The SoCal Citygate price point from the Base Case is selected as the fundamental forecast price starting from July 2032 (i.e., FY32). A linear regression was developed in the interim period to form a gradual transition between the two forecast methods.

[23] 2023 IEPR Preliminary Electric Generation Price Model, Docket 23-IEPR-03, Filed on 04/18/2023

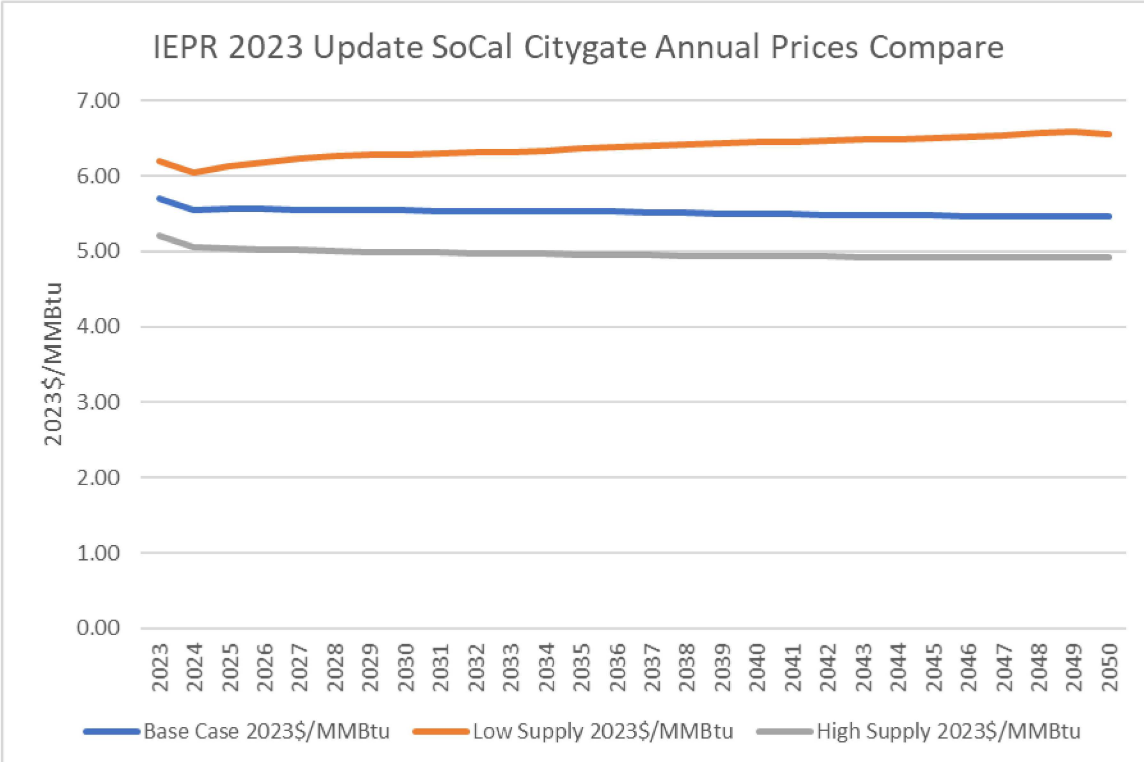

Figure 3-2 IEPR SoCal Citygate Natural Gas Price Forecast Comparison

To capture both data sources, three periods of pricing were created. The first period, FY2023/2024 through FY2026/2027, is based off BWP market quotes. The second period, FY2027/2028 through FY2031/2032 is a transition during which the higher natural gas prices from the BWP market quotes are linearly transitioned down to the expected long-term IEPR forecast prices. Finally, the third period is based solely on the data from the 2023 IEPR.

For all periods and data sources, prices were inflation adjusted to 2023 dollars. Figure 3-3 shows the monthly natural gas price forecast for the full planning horizon. The result of the forecast was a set of data providing monthly natural gas prices that were used as an input into the PLEXOS model.

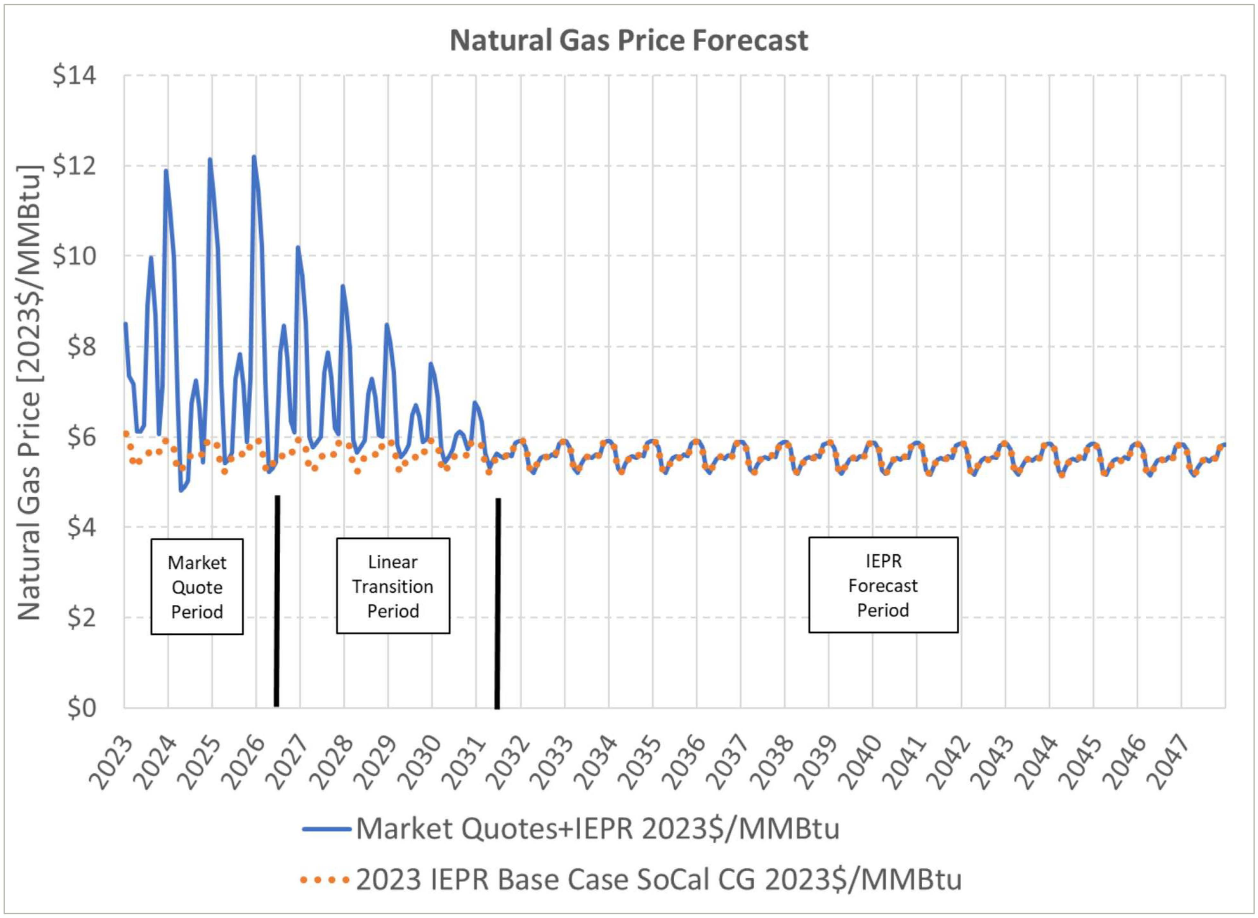

Figure 3-3 Natural Gas Price Forecast

3.2.2.3 Capital Costs

For each of the potential generating technologies considered for capacity expansion in this IRP, assumptions had to be made regarding their capital (CAPEX) and operations and maintenance (O&M) costs. Cost projections were developed by Black & Veatch and were further broken down into three regions – California, the Rockies, and regions neighboring California – to better capture geographical cost differences. These forecasts were developed based on a combination of previous assessments and projects performed by Black & Veatch and review of publicly available sources such as the Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL).

The ITC available through the federal IRA were assumed to be applicable for battery storage resources. The tax credit equals 30% of the projects' capital costs starting from 2023. The ITC is assumed to decrease to 22.5% in 2034, 15% in 2035 to 2040, and then completely phase out after 2040. The same percentages were taken out from the full values of capital costs to reflect the ITC received. This resulted in the capital costs of battery storage appearing to go up over years as opposed to other technologies whose costs decreased over time.

In this IRP, Black & Veatch assumed both solar and wind generating facilities are eligible to apply for PTC now available through the IRA. PTCs were reflected as a negative variable O&M cost in the production cost model. Capital costs of wind and solar were modeled at their full values.

As discussed in previous sections, RNG fuels were expected to be available after 2030 to meet BWP's Net Zero goal. Hydrogen technologies were not expected to be available locally in Burbank until 2040.

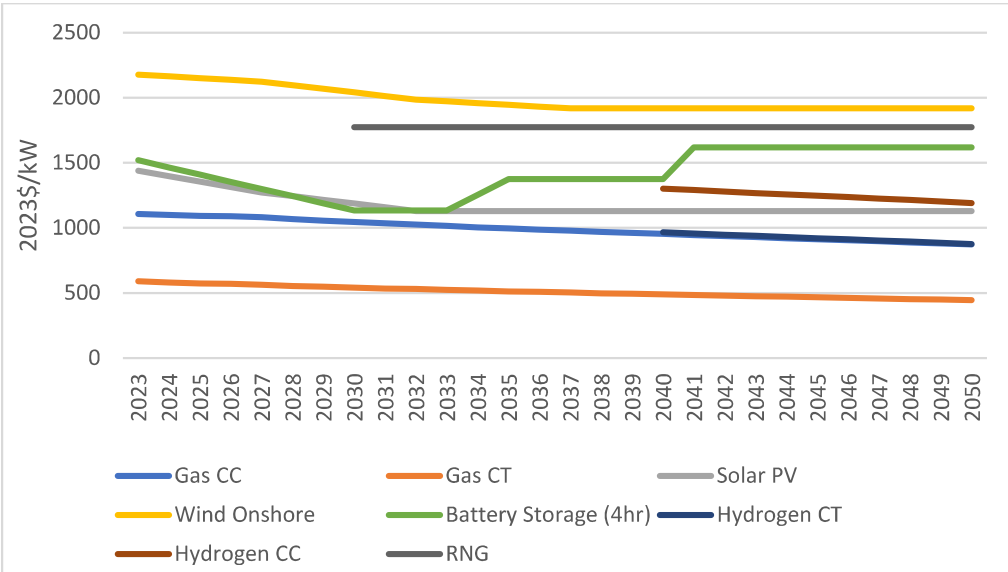

Figure 3-4 CAPEX Projections by Technology in Rockies Region

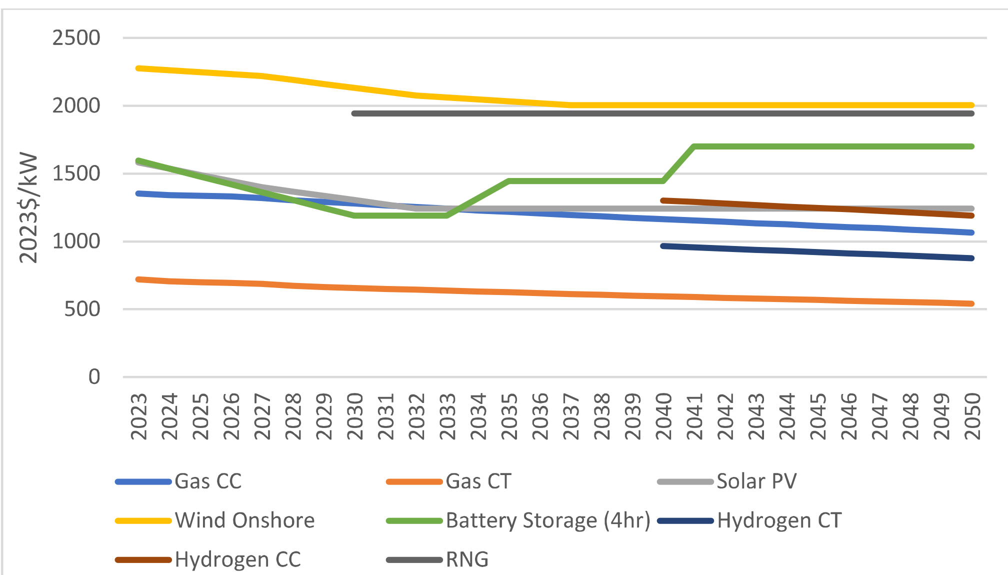

Figure 3-5 CAPEX Projections by Technology in California Region

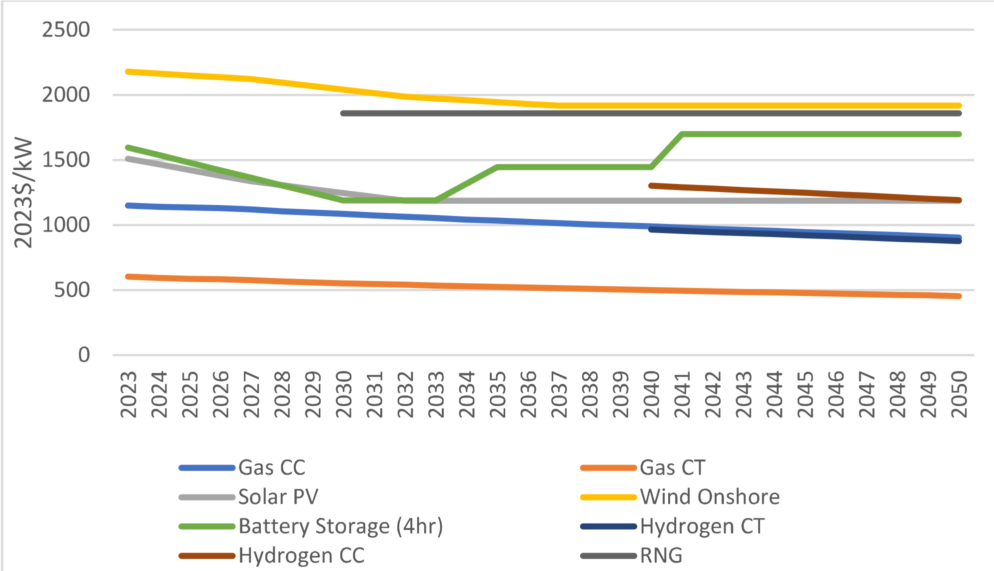

Figure 3-6 CAPEX Projections by Technology in California Neighbor Region

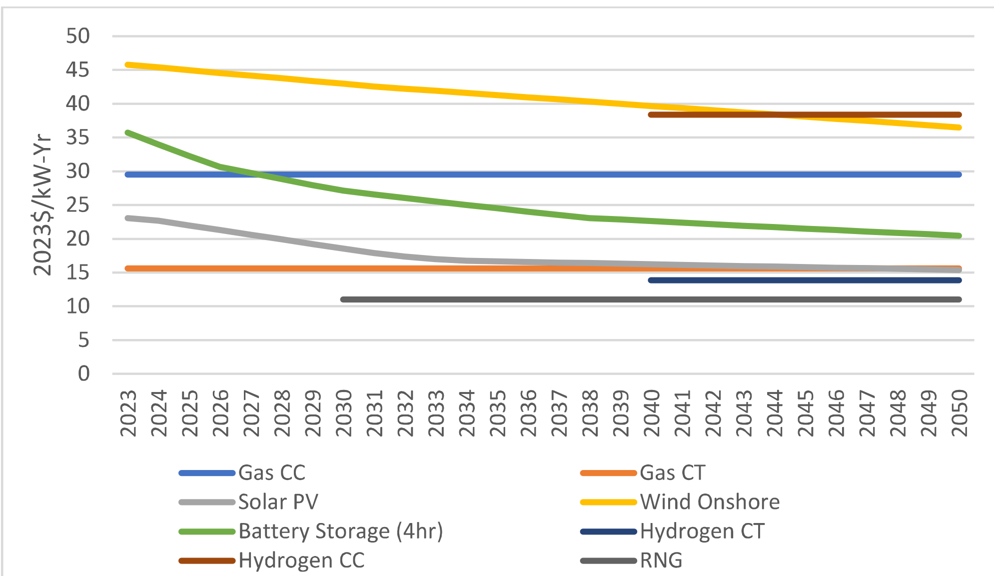

Figure 3-7 Fixed O&M Cost Projections by Technology

3.2.2.4 Base Case Assumptions

3.2.2.4.1 Existing and New Generation Resources

See Section 2.5 for the discussion of BWP's existing resources portfolio.

In order to meet BWP's RPS and emission reduction targets, Black & Veatch primarily considered renewable resources, clean alternative fuels and storages when constructing future generation portfolios. Combining the understanding of Burbank's future transmission and infrastructure readiness, Black & Veatch selected solar, wind, combined cycle gas turbine with carbon capture and sequestration (CCS), hydrogen-fueled combined cycle and combustion turbine as potential resources and technologies that can be part of BWP's future portfolio.

3.2.2.4.2 Grid Operational Efficiencies

In the modeling, five percent of transmission losses were applied on generation delivered in BWP region. This is based on historical records on BWP's resource budget. Another three percent of distribution losses were then applied to reported retail sales.

3.2.2.4.3 Energy Storage

Assumptions on energy storage are discussed in detail in Section 3.6.3 below. Lithium-ion batteries were included in PLEXOS when analyzing potential portfolios for each scenario.

3.2.2.4.4 Distributed Energy Resources

Assumptions on distributed energy resources (DER) are discussed in detail in Section 3.5.1.6 below. Forecast of DER, more specifically, distributed solar resources was developed based on 2022 IEPR baseline. It was then used as the demand side adjustment during dispatch modeling.

3.2.2.4.5 Energy Efficiency

Assumptions on energy efficiency are discussed in detail in Section 3.5.1.5 below. Similar to DER, forecast of energy efficiency was based on 2022 IEPR and was used as a demand side adjustment.

3.2.2.4.6 Short-Term and Long-Term Products

Regarding new resources, Black & Veatch estimated levelized capital carrying rate based on various financing assumptions. Existing PPA contract durations were included in the optimized modeling of each scenario.

3.2.2.4.7 RPS Procurement

BWP aims to secure most of its renewable contracts where transmission is available and already contracted for; and resources in diverse locations, with variable term lengths and ultimately, on a least-cost and best-fit basis. For any additional RPS requirements that are not met by the current and future generation portfolio, BWP would purchase RECs in various Portfolio Content Categories (PCCs). The required amount of RECs from each PCC is discussed in Section 3.6.1.1.

All SB 100 cases reached the target of 60% RPS by 2030, with both contracted renewable resources and PCC procurements. The reported amounts of RECs for each scenario assume that any excess procurement that occurs yields RECs that can be either banked for future RPS compliance or sold if there is a significant excess of RECs in a given future year. However, with the addition of the solar generation associated with IPP green hydrogen, excess RECs post 2030 are so large that the value of banking is not clear.

3.2.3 Summary of All Scenarios, Scorecard, and Recommended Strategy

Based on the feedback from the IRP survey, the STAG and the community stakeholders, a scorecard was developed to rank each scenario. The weight of the scorecard and details of the scorecard are listed below:

Table 3-2 Scorecard Details and Weighting

Item	Details	Weight
Cost/Ratepayer Impacts	The total overall cost of the portfolio (the lower the cost, the higher the weight or score)	40%
Reliability	Lower transmission losses and lower market purchases (the lower the losses and purchases, the higher the weight or the score)	40%
Environmental Stewardship	Total greenhouse gas emissions (the lower the emissions, the higher the weight or the score)	10%
Diversity	Type of resource, length or term of the contract, type of resource technology (like wind, solar, geothermal, etc.), location of resource, a mix of baseload and variable resources, etc. Diversification of resources is required under SB 350	10%
Total		100%

3.2.3.1 Scorecard Results

The scorecard rankings show that the "Basecase+Zero Carbon by 2030" scenario ranks highest. Unfortunately, the lack of contracts available to get us to RNG at the Magnolia Power Project makes this scenario invalid. As mentioned earlier, the assumptions for the IRP were taken earlier in the year and many items changed. This includes the lack of RNG contracts available and higher than expected load forecast.

Table 3-3 Scorecard Results

Metric	Weight	Basecase (meet SB 100)	Basecase+ Zero Carbon by 2030	SB 100+SB 1020+ SMR	SB 100+SB 1020+SMR+ reduction in load of 50%	Basecase+10% higher load	Basecase+10% lower load	Basecase+ New Transmission and PPA's
MODEL FOR EACH SCENARIO		PLEXOS	PLEXOS	PLEXOS	PLEXOS	PLEXOS	PLEXOS	PLEXOS
Cost/Ratepayer Impacts	40%	39%	0%	35%	37%	39%	40%	39%
Reliability	40%	24%	8%	27%	40%	21%	25%	24%
Environmental Stewardship	10%	0%	10%	3%	4%	0%	0%	1%
Diversity	10%	0%	5%	8%	8%	0%	0%	10%
Total	100%	63%	23%	72%	89%	60%	66%	75%
Rank		5	7	3	1	6	4	2

3.2.4 Emissions Summary

In September 2023 the California Air Resources Board (CARB) released an update to the "Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets."[24] The lower 2030 planning target of 129,000 metric tonnes of CO_2 equivalent ($MTCO_2e$) remained unchanged from that considered under the 2019 Burbank IRP. However, the upper 2030 planning target has been reduced from 228,000 $MTCO_2e$ to 163,000 $MTCO_2e$. As can be seen in Table 3-4, only three of the planning scenarios meet the new CARB planning targets. All the planning scenarios evaluated in this 2024 IRP report make significant reductions in CO_2 emissions with net zero emissions being achieved by no later than 2040.

Table 3-4 Greenhouse Gas (GHG) Emissions in Metric Tonnes

Year	Base Case	Net Zero by 2030	SB1020 + SMR	SB1020 + SMR w/ 50% DEV & EV Demand	10% Higher EV & DEV Demand	10% Lower EV & DEV Demand	New Transmission & PPAs
2023	343,469	351,766	342,936	342,440	343,644	343,453	343,151
2024	346,419	354,389	346,029	345,331	346,504	346,276	346,489
2025	274,157	250,672	274,276	259,156	277,337	271,225	274,147
2026	275,852	240,564	275,194	271,605	276,056	275,298	275,679
2027	253,008	214,517	251,065	234,093	255,840	249,497	252,446
2028	199,145	162,476	209,531	194,770	202,786	195,560	199,155
2029	197,464	151,629	208,328	196,170	201,797	195,280	197,612
2030	187,840	-	104,568	107,072	190,767	185,670	187,496
2031	197,292	-	118,301	115,091	200,617	194,559	197,037
2032	193,522	-	117,989	107,706	197,678	189,033	192,060
2033	178,373	-	137,145	125,283	179,676	175,597	177,566
2034	163,004	-	126,306	111,543	166,528	163,483	164,956
2035	157,107	-	95,176	84,908	159,777	153,517	112,192
2036	146,122	-	92,856	80,454	149,139	141,160	112,569
2037	129,758	-	88,598	71,872	132,656	126,115	108,640
2038	115,161	-	85,757	63,719	113,473	109,703	88,699
2039	92,111	-	85,474	55,482	90,526	88,083	70,069
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-

3.3 STANDARDIZED TABLES

Due to formatting constraints, copies of the CEC's Standardized Tables containing the results of the two preferred scenarios chosen through the scorecard analysis described in Section 2.6.8 (the "New Transmission & PPAs" and "SB1020+SMR" options) will be submitted separately to the CEC.

[24] California Air Resource Board, "Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets: 2023 Update," https://ww2.arb.ca.gov/sites/default/files/2023-09/sb350-final-report-2023.pdf

3.4 SUPPORTING INFORMATION

The assumptions that were relied on in the analysis documented in this report are discussed in the relevant sections and footnoted and linked to online resources where appropriate. Any additional analyses, data, or other materials not already contained in, or referenced by, the body of this IRP report will be provided on request in order to facilitate the CEC's review.

3.5 DEMAND FORECAST

Burbank Water and Power (BWP) serves the electricity needs of Burbank and its people. In utility terms, these needs are called "demand." BWP serves Burbank's demand by delivering power through the electrical system: the network of wires, transformers, switches, and other equipment that make up the electric grid. BWP generates a portion of this electricity itself, purchases some through power plant contracts, and buys energy from the electricity markets when it is necessary to meet customer demand.

Managing and forecasting Burbank's future demand for electricity is necessary to ensure current and future affordability and reliability. As BWP moves forward, there will be challenges in forecasting BWP's demand due to changing customer use patterns brought about by new energy efficiency measures, an increasing adoption of electric vehicles, generation contributions from customer-owned rooftop solar, and legislative mandates to reduce Greenhouse Gas (GHG) emissions. Therefore, it is essential to understand hourly demand profiles, annual energy needs, and peak energy requirements. This information will help inform resource procurement decisions made by BWP as it makes plans to meet the unique challenges of Burbank's energy future.

3.5.1 Demand Forecast Methodology and Assumptions

A multi-step process is used to forecast the demands that BWP must account for in its long-term planning. The methodology and process used for forecasting annual demand as well as the detailed hourly demand profiles is described below.

The gross energy demand forecast for Burbank comprises energy demands for residential, commercial, future development, and future electric vehicle components. Gross energy demand is then offset by savings from energy efficiency measures and the contributions from distributed generation to calculate net energy demand.

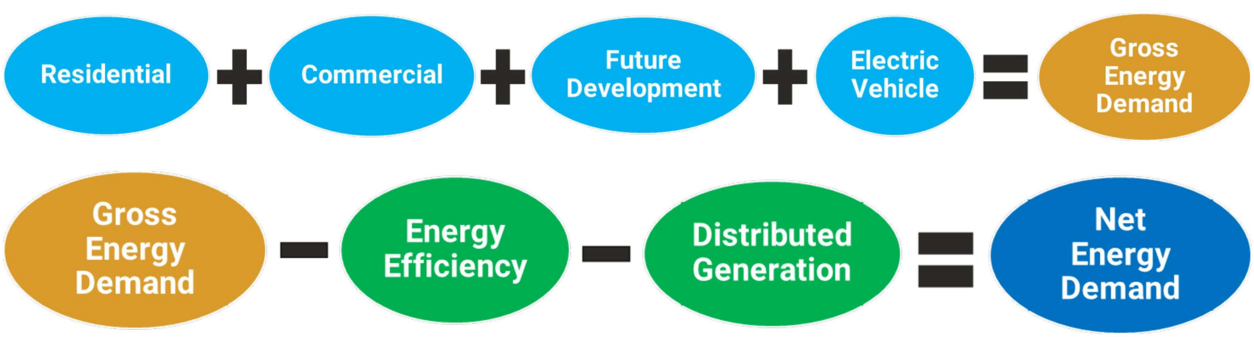

Figure 3-7 Gross and Net Energy Demand Components

3.5.1.1 Residential Energy Demand

The forecasted residential base energy demand was based on a regression analysis of historical demand data for Burbank. Annual residential retail sales from 1998 through 2022 were used along with city population, average personal income, and the annual number of cooling degree days

(CDD) to develop the appropriate regression coefficients. Once the relationship between these variables was determined, annual residential energy demand was calculated for the years 2023 through 2047. During that forecast period, the residential base energy demand is estimated to grow at a Compound Annual Growth Rate (CAGR) of 0.5%.

3.5.1.2 Commercial Energy Demand

The commercial base energy demand was forecasted in a similar fashion to the residential base energy demand. Historic demand data from 1998 through 2022 was used with a set of independent variables to perform a regression analysis. For commercial energy demand, the chosen independent variables were city population, the amount of commercial floor space, average personal income, and the number of employees working in the commercial sector. Like the residential base energy demand, annual commercial base energy demand was calculated for the years 2023 through 2047. During that forecast period, the commercial base energy demand is estimated to grow at a CAGR of 0.8%.

3.5.1.3 New Development Energy Demand

Known development projects planned within Burbank were reviewed and their impact on residential and commercial energy demands was considered. The estimated peak energy demand in megawatts for each development project was used together with a load factor of 43%[25] and a conservative project success factor of 60% to calculate the total annual energy demand impact. The success factor was used to account for any potential delays or cancellations of these development projects and to account for any potential differences between the actual usage from these development projects vs. the peak energy demand assumed for designing the required distribution system. Once found, this new development energy demand was phased in over a period of seven years starting in 2025 to account for the time it would take for the projects to be completed.

3.5.1.4 Electric Vehicle Energy Demand

Annual electric vehicle energy demand through 2035 was based on a blend of the California Energy Commission's (CEC's) 2022 Integrated Energy Policy Report's (IEPR's) Additional Achievable Transportation Electrification (AATE) scenarios. The Burbank-Glendale (BUGL) planning area AATE scenarios were scaled down using data from the 2022 IEPR Load Serving Entity (LSE) and Balancing Authority (BA) data to derive Burbank's share of the forecast electric vehicle energy demand. In addition to the baseline AATE forecast from the IEPR, Burbank's electric vehicle energy demand was also based on the increasing rates of electric vehicle adoption shown in AATE Scenarios 2 and 3. A blending of the three scaled AATE scenarios, shown below in Figure 38, was used to calculate the annual electric vehicle energy demand for Burbank. The blending of the 3 AATE scenarios was used to account for an adoption rate for electric vehicles that is anticipated to increase over time. In 2022, the California Air Resources Board (CARB) promulgated the "Advanced Clean Cars II" regulations requiring that by 2035 all new cars and light trucks sold in California will have to be zero-emission vehicles. Since the AATE scenarios only contained a forecast though 2035, that data was extrapolated out through 2047 using a second order polynomial regression model.

[25] 43% load factor is based on the historical load factor data for the Burbank region.

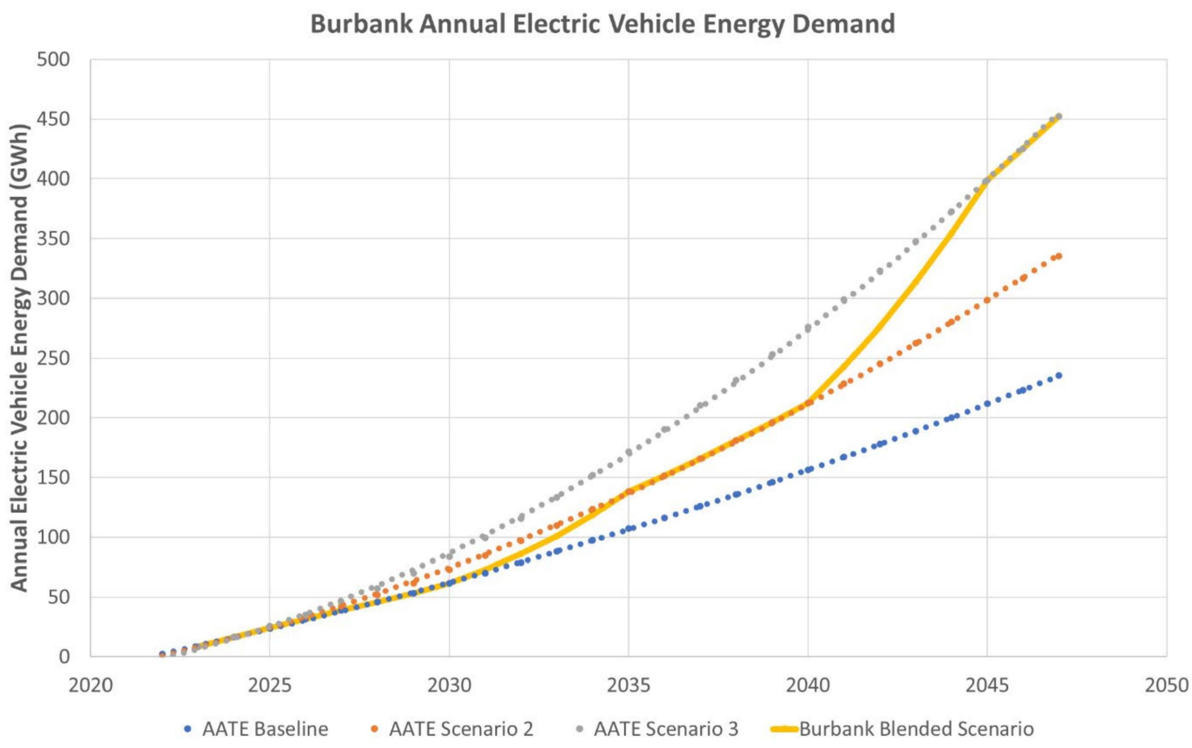

Figure 3-8 Forecast Electric Vehicle Energy Demand for Burbank

3.5.1.5 Energy Efficiency Savings

The forecast for Burbank's energy efficiency savings was developed using data taken from the CEC's 2022 IEPR's AAEE Scenario 3. Unlike the AATE data, the AAEE data was available through 2050 and could be directly used for the entire planning horizon without the need for extrapolation. As can be seen in Figure 3-9, the annual increases in energy efficiency savings are assumed to decrease over time. Benefits from the implementation of energy efficiency programs are expected to eventually saturate as the most impactful and cost-effective changes are made first and programs with smaller benefits are implemented later.

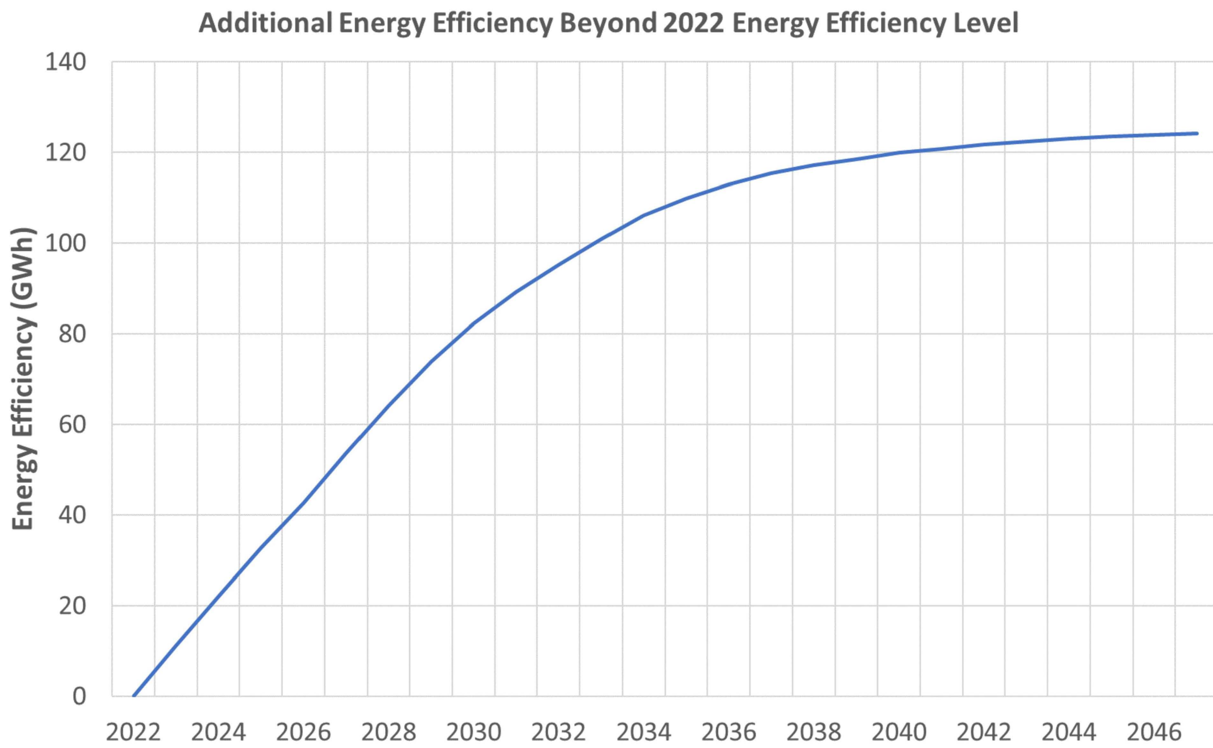

Figure 3-9 Forecasted Energy Efficiency Savings for Burbank

3.5.1.6 Contributions from Additional Distributed Generation

The forecast for Burbank's additional distributed generation, beyond what is already present in the city, was based on data taken from the CEC's 2022 IEPR baseline forecast. The 2022 IEPR baseline forecast annual distributed generation data was only available through 2035; therefore, it was extrapolated out through the end of the planning horizon using the same method as was used for the AATE data. A trend toward increasing contributions from distributed generation is in line with the general trends seen in the broader energy markets. Incentives like those that are a part of the Inflation Reduction Act are expected to further encourage expansion of customer-owned generation resources.

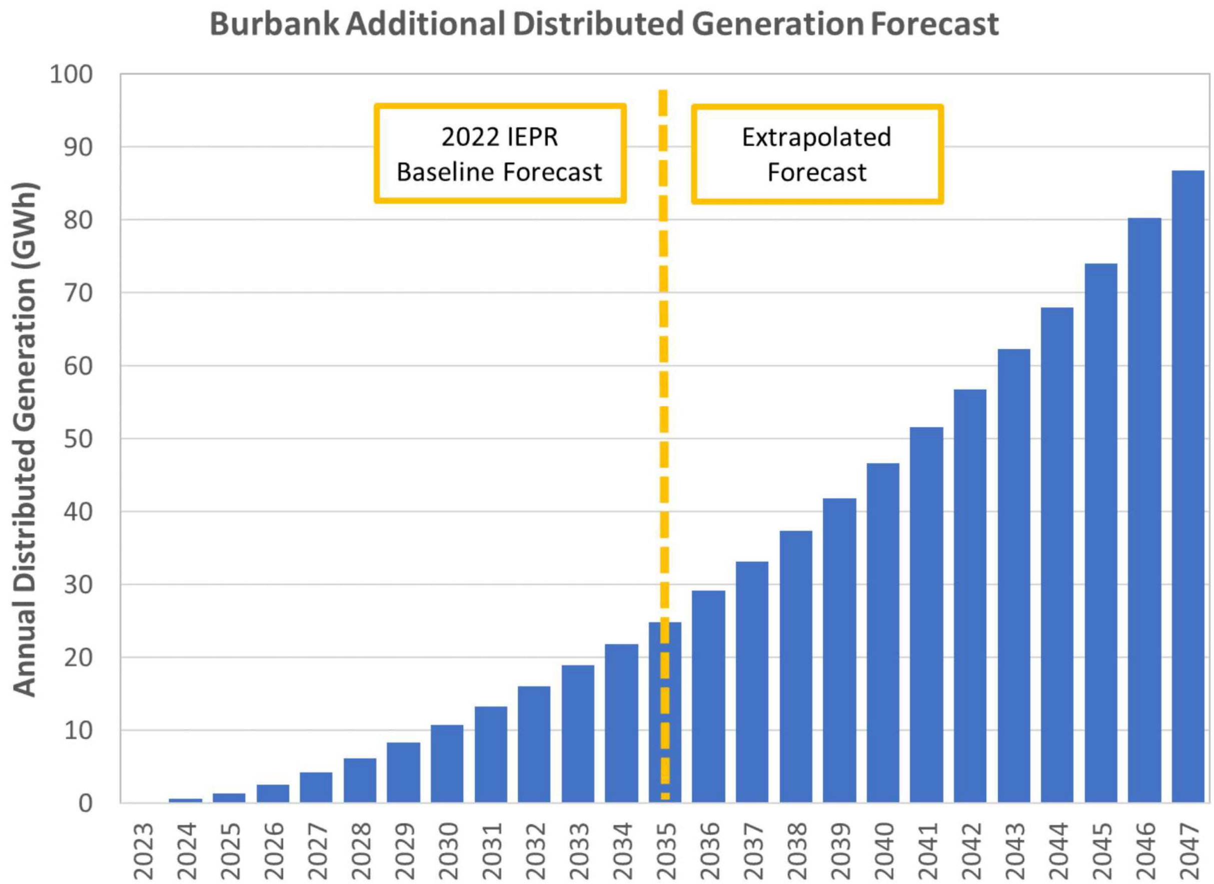

Figure 3-10 Forecasted Additional Distributed Generation for Burbank

3.5.1.7 Annual Peak Energy Demand

Another regression model was used to develop the annual peak values for Burbank's non-electric vehicle gross energy demand. Electric vehicle energy demand was not included in this peak energy demand regression due to its drastically different hourly demand profile compared to residential and commercial demands. The non-electric vehicle gross energy demand comprises residential, commercial, and non-electric vehicle development demands. For the peak energy demand regression analysis, historical net peak was the dependent variable and historical net demand and maximum CDD were the independent variables. This regression analysis provided the coefficients necessary to forecast peak energy demand values. Max CDD for the 2023-2047 peak forecast was assumed to be weather normal. The peaks for electric vehicles, energy efficiency, and distributed generation are a function of their annual forecasts and their hourly shapes.

3.5.2 Determination of Hourly Demand Shapes

Beyond the annual values for each of the contributing categories that make up Burbank's net energy demand, hourly demand profiles for contributing categories for each year in the planning horizon (2023-2047) were also generated. The hourly data is used for detailed modeling of future energy needs and determination of the best types and amounts of generation that will be required to meet them.

3.5.2.1 Residential. Commercial, and Future Development Hourly Demand

The hourly demand shape for residential, commercial, and future non-electric vehicle development energy demands was adopted from Burbank's actual 2018 demand profile. The 2018 demand profile was found to be the most weather "normal" year based on historical CDD and energy consumption data; therefore, it was used as the basis for the creation of the hourly demand profile for this part of the overall net system demand. PLEXOS was used to build the hourly forecast based on annual demand, peak, and the 2018 demand profile.

3.5.2.2 Electric Vehicle Hourly Demand

The 2022 IEPR electric vehicle hourly demand profile for the CAISO planning scenario was scaled down to match Burbank's forecast electric vehicle demand. Since that IEPR demand profile did not span the entirety of the planning horizon, the last year of that forecast (2035) was used as the basis for the hourly demand shape in the years 2036-2047.

3.5.2.3 Hourly Savings from Energy Efficiency

The hourly profile for energy efficiency savings was also taken from the 2022 IEPR. Scenario 3 from the 2022 IEPR AAEE & Additional Achievable Fuel Substitution (AAFS) forecasts was used in conjunction with the 2022 IEPR AAEE Hourly Impacts forecast for the BUGL planning area to create the hourly energy efficiency forecast for the entire planning horizon. The BUGL hourly forecast was scaled down to match the Burbank Annual AAEE Scenario 3 forecast from the 2022 IEPR. Since both IEPR sources included data through 2050, no extrapolation or regression was required.

3.5.2.4 Hourly Contributions from Distributed Generation

An hourly solar generation profile for the Los Angeles area was used together with the annual distributed generation forecast described above to create the hourly contributions from distributed generation located within Burbank.

3.5.2.5 Sum of Hourly Demand Profiles

Once all the hourly demand profiles were completed, (residential and commercial energy demand including the demand from new developments, electric vehicle energy demand, energy efficiency savings, and energy contributions from distributed generation), they were all combined on an hourly basis to create the final hourly demand forecast. In the figures below, the forecasted change in the average summer and winter hourly demand profiles can be seen. As time passes, the effects of increased demand can be seen as the hourly demands shift upwards and peak demands increase. The adoption of electric vehicles can be seen in the more pronounced energy usage in the overnight hours. This is particularly evident in Figure 3-12 where the winter peak is shifted towards the overnight hours due to electric vehicle charging.

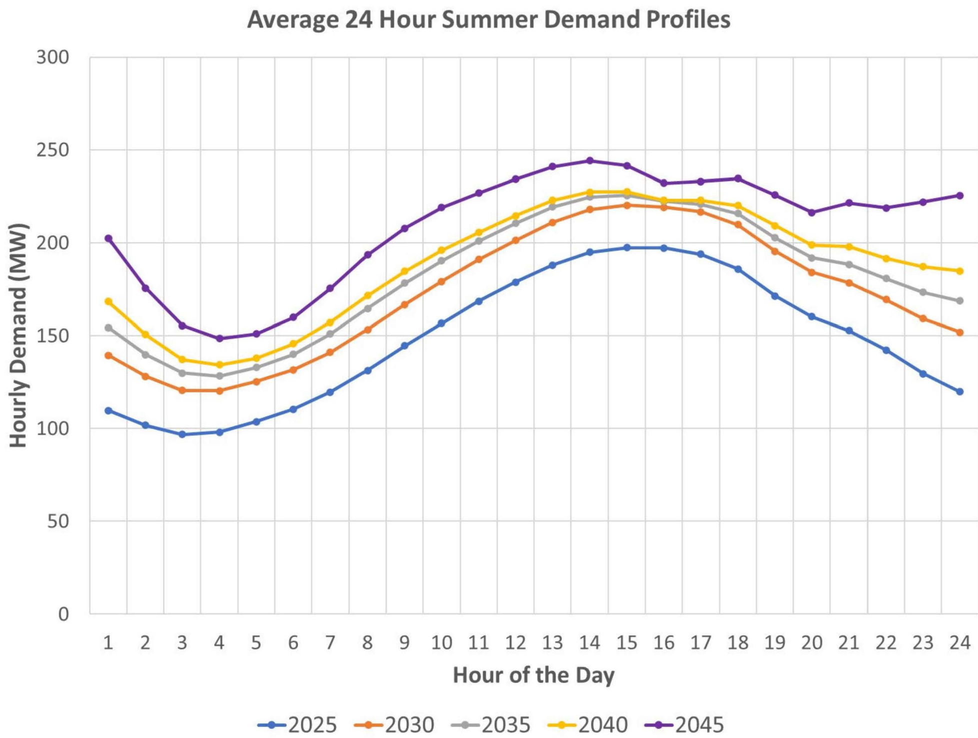

Figure 3-11 Average Hourly Summer Demand Profiles

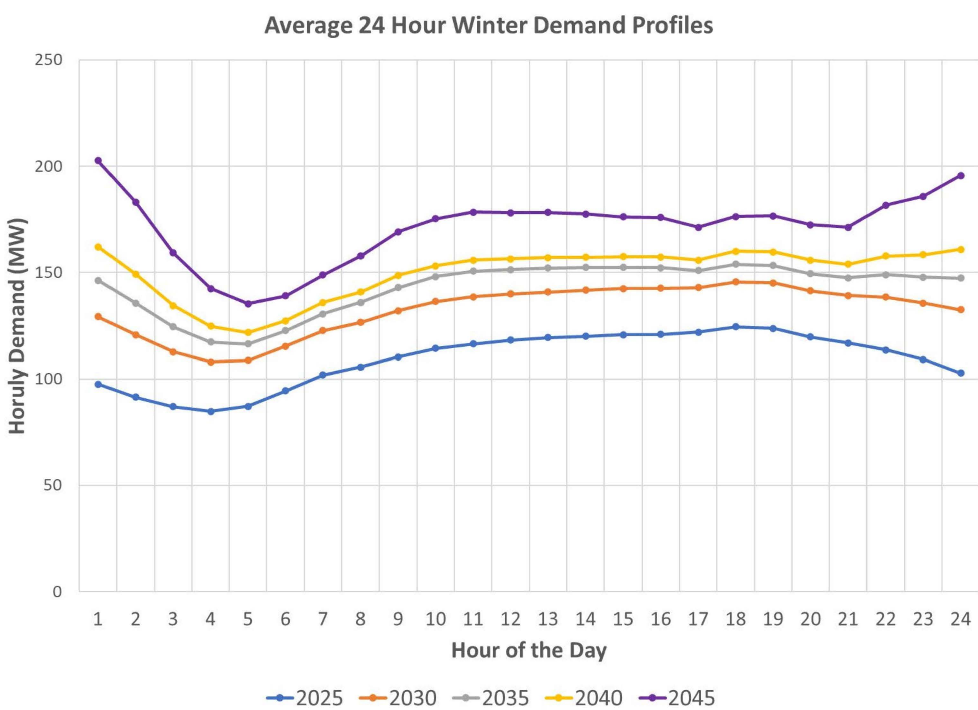

Figure 3-12 Average Hourly Winter Demand Profiles

3.5.3 Results of Demand Forecast

In the historic demand data from 2018-2022 listed in Table 3-5 and Figure 3-13 below, the annual net energy demand and net peak energy demand for Burbank show a temporary decrease in 2020 and 2021 that is associated with the impacts of the COVID-19 pandemic. The forecast from 2023-2047 assumes that demand will return to "pre-COVID" levels and will increase largely due to new residential and commercial developments and the increasing adoption of electric vehicles.

The forecasted demand for Burbank from 2023-2047 is also provided in Table 3-5 and Figure 3-13 below. Annual net energy demand is given in units of gigawatt-hours (GWh) and annual net peak energy demands are given in units of MW.

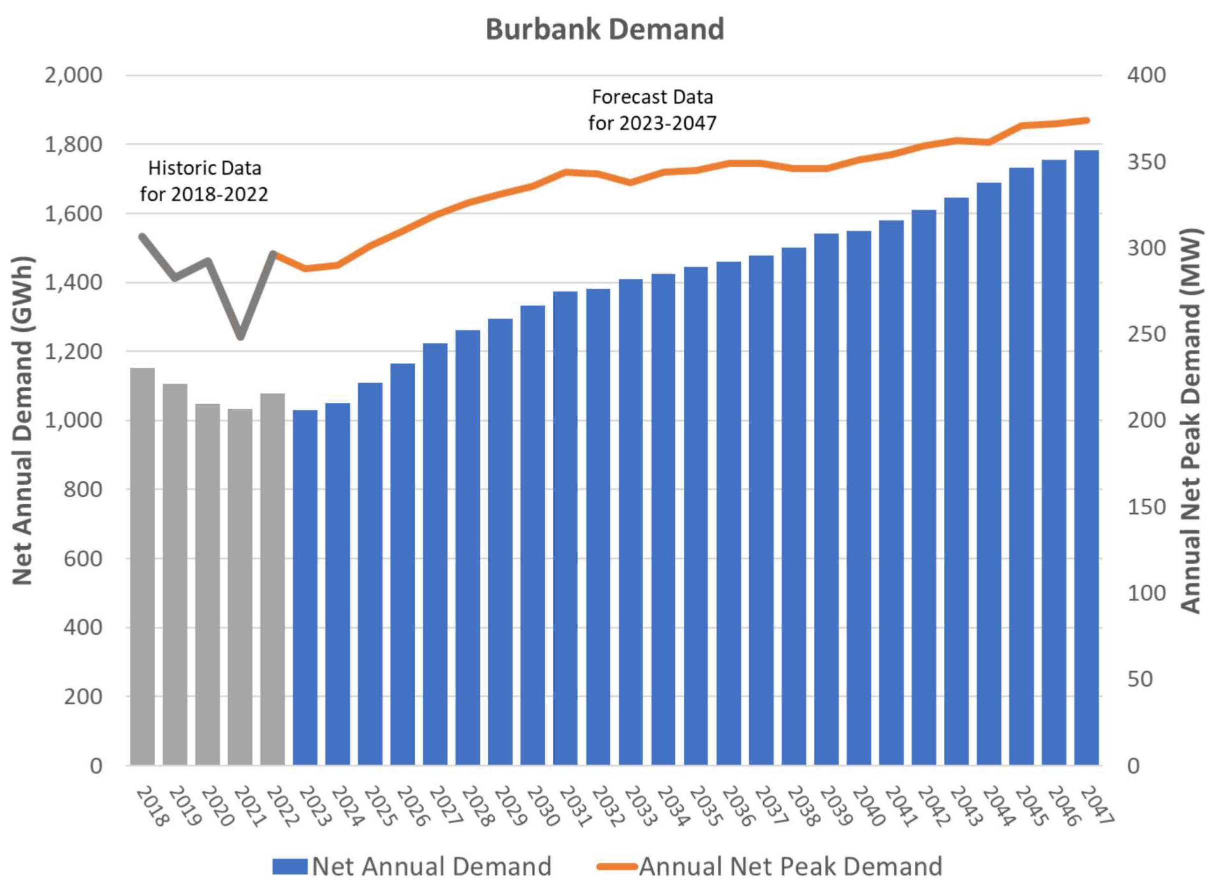

Figure 3-13 Forecast Net Annual Demand and Annual Net Peak Demand

Table 3-5 Annual Net Energy Demand & Net Peak Energy Demands

Year*	Net Energy Demand (GWh)	Net Peak Energy Demand (MW)**
2018	1,151	306
2019	1,108	283
2020	1,049	292
2021	1,033	248
2022	1,079	297
2023	1,004	288
2024	1,023	290
2025	1,078	301
2026	1,132	310
2027	1,186	319
2028	1,217	326
2029	1,250	331
2030	1,284	336
2031	1,324	344
2032	1,332	343
2033	1,342	338
2034	1,355	344
2035	1,373	345
2036	1,383	349
2037	1,396	349
2038	1,409	346
2039	1,423	346
2040	1,437	351
2041	1,467	354
2042	1,499	359
2043	1,534	362
2044	1,573	361
2045	1,615	371
2046	1,639	372
2047	1,665	374

* Historic demand data is provided for years 2018-2022. The forecast is for years 2023-2047.
** The forecast peak demand data includes transmission losses.

3.6 RESOURCE PROCUREMENT PLAN

3.6.1 Diversified Procurement Portfolio and RPS Planning Requirements

In December 2021, BWP revised its Renewable Energy Resources Procurement Plan to incorporate the target of procuring at least 60% of annual retail electricity sales from eligible renewable resources by the end of 2030. Post-2030, eligible renewable resources are to continue to meet or exceed that 60% target.

Most of the long-term renewable energy contracts solicited by BWP are done jointly though its membership in the SCPPA. By joining with other SCPPA members to purchase renewable energy, BWP is able to access a more diverse set of projects that it would be otherwise unable to participate in due to its relatively small energy demand within the broader electricity market.

BWP splits its procurement of renewable energy between both baseload and peaking resources and seeks to include a diversity of contracts that include both fixed and market-based energy prices.

3.6.1.1 Forecasted RPS Procurement Targets

Included in the table below, taken from the current BWP Renewable Energy Resources Procurement Plan, are the procurement targets for compliance periods leading up and following the December 31, 2030 deadline to reach 60% RPS.

Table 3-6 RPS Compliance Requirements[26]

Burbank Water and Power California Energy Commission RPS Procurement Requirements by Calendar Year				
California RPS Mandatory Procurement Requirement	Compliance Period 4	Compliance Period 5	Compliance Period 6	Compliance Period 7+
	1/1/2021-12/31/2024	1/1/2021-12/31/2027	1/1/2028-12/31/2030	3 calendar year blocks
	44% RPS by 12/31/2024	52% by 12/31/2027	60% RPS by 12/31/2030	60% RPS
PCC 1 Minimum	≥ 75% of Net Procurement Requirement			
PCC 2 Maximum	≤ 25% of Net Procurement Requirement			
PCC 3 Maximum	≤ 10% of Net Procurement Requirement			
LTR	At least 65% of all RPS contracts must be long-term in duration (at least 10 years in duration)			

3.6.1.2 Renewable Procurement

The resource portfolios for each of the planning scenarios are described in Section 2.6. The figures provided for the different scenarios include data on the forecasted capacity, total generation in

[26] Burbank Power and Water, Renewable Energy Resources Procurement Plan & Enforcement Program, Version 3, December 2021.

MWh, and annual RPS percentages for each of the years in the study period. The same information is also included in the Standardized Tables in Section 3.3.

3.6.1.3 RPS Procurement Plan

The current BWP Renewable Energy Resources Procurement Plan & Enforcement Program is included as Attachment 1 to this IRP report.

3.6.1.4 Other RPS Procurement Plan Information

3.6.1.4.1 City Council Discretion and Cost Limitations

Within the BWP Renewable Energy Resources Procurement Plan, it is acknowledged that certain future circumstances may impact its ability to comply with RPS procurement targets. Under these circumstances, the Burbank City Council may choose to delay the timely procurement of renewable energy:

- Inadequate Transmission Capacity
- Permitting or Interconnection Delays
- Unanticipated Curtailment or Unforeseeable Circumstances
- Unanticipated Increase in Retail Sales Due to Transportation Electrification

In the circumstances listed above, there may be occurrences beyond the control of BWP that could limit its ability to procure or receive renewable energy on a schedule that supports meeting its RPS targets or its ability to procure renewable energy at reasonable prices.

The Burbank City Council has the ability to set a cost limitation in place if it determines that there would be adverse cost impacts to ratepayers due to the procurement of new long-term renewable energy resources. If the City Council uses its authority to delay or modify any of the RPS procurement targets, it will do so at a public meeting and ensure that all necessary and reasonable efforts have been made to achieve compliance.

3.6.1.4.2 Enforcement Program

The responsibility of executing the Renewable Energy Resources Procurement Plan falls to the General Manager of BWP. If the General Manager determines that BWP will not meet one of its RPS procurement targets, they will notify the Burbank City Council in a public meeting and present a plan laying out the ways in which BWP will seek to bring itself back into compliance.

3.6.2 Energy Efficiency and Demand Response Resources

BWP manages a comprehensive portfolio of Energy Efficiency (EE) programs for residential and commercial customers to assist with energy conservation and peak shaving measures. One of these EE programs is the Home Improvement Program (HIP). HIP offers energy-water surveys and efficiency measure installations to all Burbank single-family residential, multi-family residential, and multi-family common area customers. A total of 587 customers participated in the HIP in FY2022/2023.

BWP also offers a Refrigerator Exchange Program. This program offers income-qualified customers a new Energy Star-Certified refrigerator in exchange for their old, inefficient refrigerator. The Refrigerator Exchange Program had 74 refrigerators exchanged during FY2022/2023. BWP's Shade Tree Program provides an arborist visit and delivers shade trees to help customers shade their properties, reduce A/C usage, and clean the air. The program delivered 204 trees during FY2022/2023. BWP's A/C Replace it Before it Breaks program assisted 36 customers replace their old A/C systems and resulted in 19 rebates issued during the fiscal year. Some additional EE programs include residential and commercial rebates for the purchase and installation of high efficiency retrofit measures and LivingWise energy/water efficiency education and kits for 6th graders. Figure 314 shows the EE savings BWP saw in FY2022/2023.

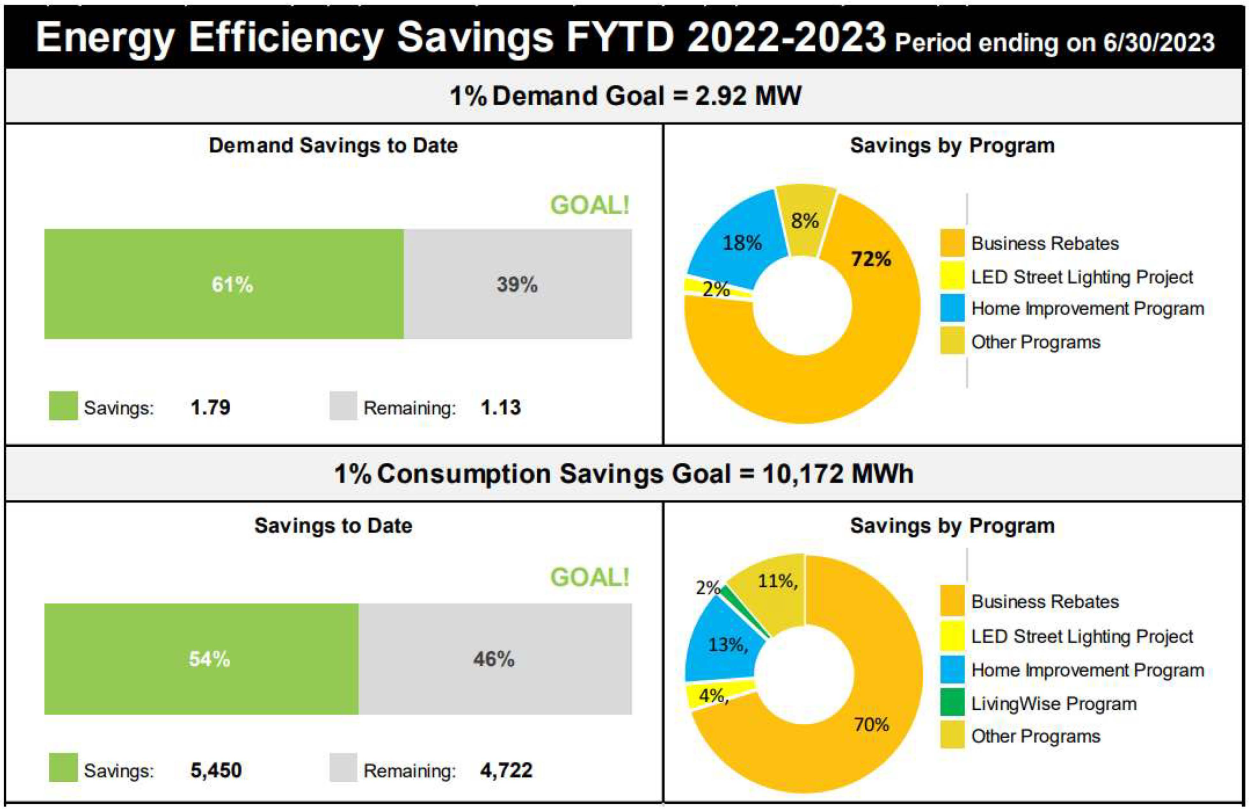

Figure 3-14 Energy Efficiency Savings FYTD 2022-2023

These existing levels of EE measures were incorporated into the residential and commercial demand forecasts. For more information about historical EE measures in BWP, see Table 4-1. The incremental EE forecast used into the model comes from the California Energy Commission's (CEC's) Additional Achievable Energy Efficiency (AAEE) Scenario 3 forecast for BWP. For more discussion on the incremental EE forecast, see Section 3.5.1.5.

While BWP offers several energy efficiency and conservation programs to its customers, it did not offer any Demand Response (DR) programs while this IRP's planning scenarios were being developed. However, BWP has requested voluntary peak load reductions from its residential customers in previous summers during high system load days as part of a "behavioral DR" pilot. It has also reduced certain Burbank demands during the heat dome even in early September 2022 as part of a new CEC program called Demand Side Grid Support (DSGS). BWP is aiming to expand DR offerings across its customer base such as a Bring Your Own Device (BYOD) program for residential and small commercial customers and the facilitation of an expanded DSGS program for larger commercial customers.

A BYOD program allows utility customers to enroll certain types of devices in a program and have the devices receive signals to reduce electricity usage during DR events. In return, customers earn a monetary incentive each year by participating in the program. The most common type of BYOD program is for customers with smart thermostats, where utilities can use Distributed Energy Resource Management Systems (DERMS) to turn up the temperature on participating thermostats by several degrees, thereby reducing the electricity required by the air conditioner or heat pump. This temperature increase is generally preceded by about an hour of "precooling," where the premise is cooled to a temperature below the thermostat setpoint to lessen the impact of the event. The BYOD program proposed in the current scope of services is a smart thermostat program, but the DERMS could host other programs if BWP decides to expand offerings in the future.

The ability of a BYOD program to directly reduce cooling load from customers enrolled in the program will allow BWP to reduce system load during peak periods and provide a more reliable load reduction than behavioral DR. Reducing cooling load lowers operating costs by reducing energy purchases during the most expensive market periods and reduce stress on the grid during heat wave events.

BWP commenced its first year of the BYOD smart thermostat program in September 2023. Summer 2024 will be the first year of full participation from May 1st – October 31st. Table 37 describes the program parameters for this DR initiative.

Table 3-7 BYOD Smart Thermostat Program Parameters

BYOD Smart Thermostat Program Parameters	
Season Window for Events:	May 1st to October 31st
Available Days:	Monday-Friday, no holidays
Control Window:	12:00 pm - 09:00 pm local
Scheduling Lead time:	Typical: 24 hours Minimum: 1 hour
Maximum Number of Events:	No more than 3 events per week No more than 20 events per DR season
Maximum Event Duration:	4 hours

3.6.3 Energy Storage

Energy storage resources will play a key role in best positioning BWP's portfolio for the clean energy transition. As stated in Section 2.1.4, energy storage will be needed to address the intermittency of renewable resources and are required to properly integrate them while maintaining reliability. One phenomenon energy storage resources help mitigate is the "Duck Curve", which will only worsen as renewable penetration increases to meet BWP's energy needs as well as achieve its RPS targets. The Duck Curve is what some call the net demand shape after incorporating the contributions of intermittent resources into the demand profile. This net demand profile can drop dramatically as solar generation increases in the middle of the day; however, solar generation might not last through the peak load hours in the evening which causes a sharp increase in the net demand profile as the sun sets. The result is that the system will need to respond quickly to potential demand increases while solar generation is declining at the same time. Energy storage resources help mitigate the Duck Curve in two ways. Firstly, when solar generation is high in the middle of the day, batteries can increase system demand by using the solar generation to charge and reduce the need to possibly curtail those solar resources. Secondly, energy storage can then use that stored energy to help with meet system demand and ramping needs in the evening as solar generation is on the decline, but the system is still experiencing high demand.

3.6.3.1 Demand-Side Energy Storage

Demand-side energy storage typically takes the form of batteries that are purchased and installed by individual residential or commercial customers and are usually paired with solar photovoltaic systems. A combined solar + storage system allows a customer to store energy generated during times of maximum generation and then consume that energy later. This can help to moderate peak demands at an individual customer level. The capacity of demand-side storage systems are typically in the 5 – 20kWh range, but can be larger depending on the application. BWP has existing requirements for the design and installation of demand-side energy storage systems.[27] Currently, there are 21 installations of demand-side energy storage systems in BWP's service territory. As shown in Figure 3-21, these installations equate to 150kW/540.8kWh of storage capacity.

3.6.3.2 Supply-Side Energy Storage

Supply-side energy storage is energy storage at a utility scale. Power output of these facilities can be many megawatts and the capacities of the largest facilities in operation can reach into the hundreds of MWh. Energy storage facilities that are connected to the transmission grid serve a similar purpose as demand-side energy storage, but at scales hundreds or thousands of times larger. Similar to demand-side energy storage, supply-side energy storage can absorb energy when renewable generation is greater than customer demand and then discharge it when it is needed the most. For this IRP analysis, 4-hour lithium-ion batteries were the only energy storage systems evaluated and incorporated into PLEXOS as an available energy storage resource.

3.6.3.3 Impact of Energy Storage on Base Case

To highlight the potential system impact of energy storage resources in Burbank's energy future, the Base Case sensitivity scenario was re-run with all standalone energy storage removed from the portfolio. The analysis confirmed that energy storage resources play a key role in a reliable and diversified portfolio.

Figure 315 illustrates how the standalone battery energy storage system (BESS) assets mitigated the Duck Curve. The data was taken from the peak summer day in 2040 and it shows the batteries increasing the net system demand in the middle of the day while the batteries are charging and then decreasing the net system demand in the evening when the stored energy is discharged. Another point of interest is that the ramping needs from the middle of the day to the evening are lower and the demand profile is not as steep.

---

[27] Burbank Water and Power, "Electrical Interconnection and Metering Agreement for Solar Electric Generating Facilities and/or Battery Energy Storage Systems," https://www.burbankwaterandpower.com/images/administrative/downloads/BWP_AppendixD_SolarInterconnectionAgreement_May2018.pdf

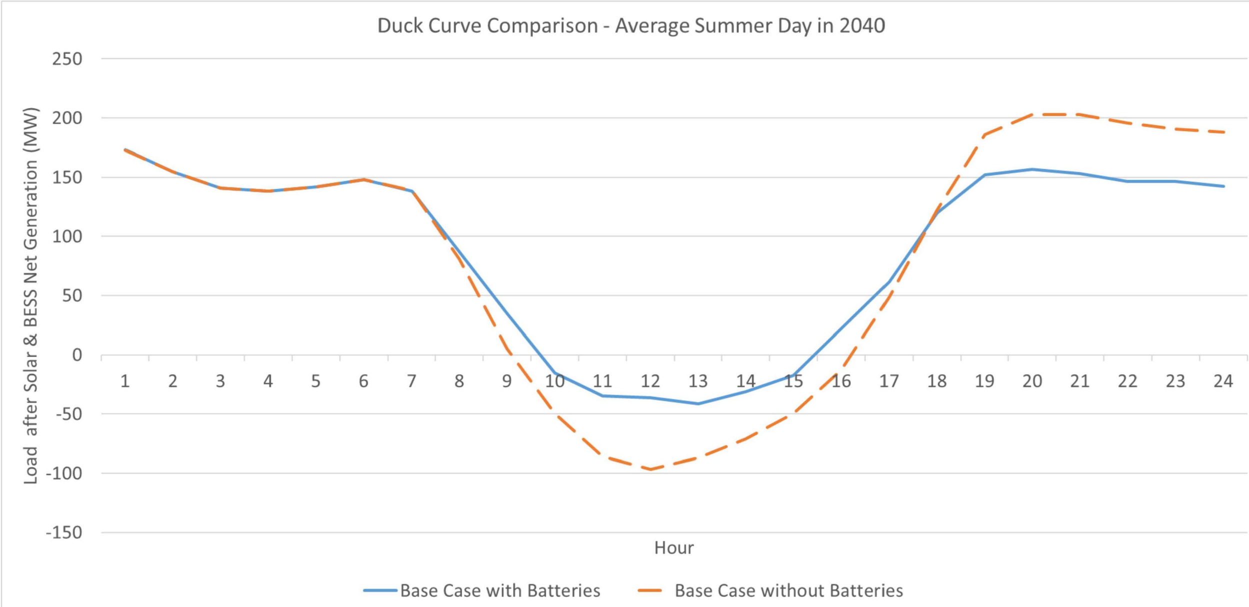

Figure 3-15 Example: Battery Impact on the Duck Curve[28]

Figure 316 shows how energy storage in the Base Case reduced the amount of solar generation curtailed by the PLEXOS model. The reason for this is that the Base Case without standalone BESS resources had materially higher solar curtailment due to not being able to efficiently move the energy around with storage. This results in a demand profile that assumes no solar curtailment to accentuate the Duck Curve phenomenon. Furthermore, using available energy is a better representation of what BWP is striving to do, which is to maximize the value of the assets they procure. Curtailment lowers the utilization and overall value of renewable assets, especially in light of the Inflation Reduction Act (IRA) and the production tax credits associated with renewable generation.

[28] Solar curtailment was removed from Figure 2-15 to better illustrate the impact storage assets have regarding the Duck Curve.

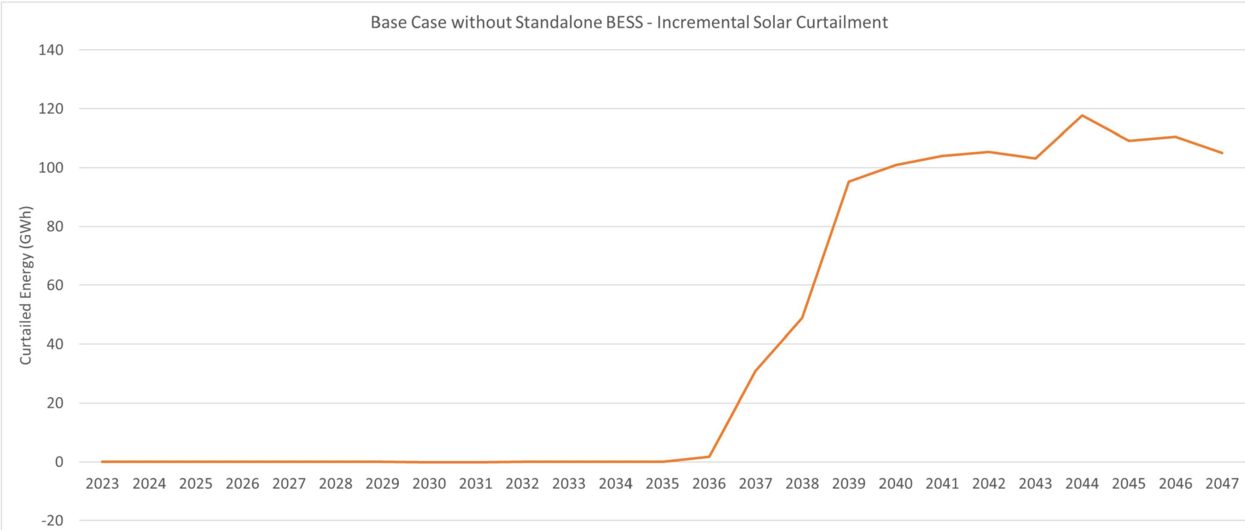

Figure 3-16 Battery Impact on Annual Solar Curtailment

3.7 SYSTEM AND LOCAL RELIABILITY

3.7.1 Bulk Transmission Reliability

BWP is a member of LADWP Balancing Area (BA). As such, bulk transmission (i.e., above 69 kV) is the responsibility of LADWP. Accordingly, bulk transmission system reliability is not a BWP responsibility outside of operating its electric system and resources in accordance with the conventions established by the Western Electricity Coordinating Council (WECC) and commonly accepted utility practice.

3.7.2 Distribution Reliability

BWP monitors Burbank's electric system performance in order to measure and maintain electric reliability. During calendar year 2022, BWP maintained an availability rate of 99.999% with a system average interruption of less than 5 minutes per customer.[29] BWP's continuing excellence in system performance was recognized in 2021 when it was presented with a Reliable Public Power Provider (RP3) award by the American Public Power Association and earned its highest possible score.[30] This level of performance was achieved while maintaining customer rates at levels lower than the average California customer.

---

[29] "City of Burbank, Burbank Water and Power, Staff Report," dated February 2, 2023, page 19, https://www.burbankwaterandpower.com/images/administrative/downloads/BWP_MonthlyOpsReport_February2023.pdf

[30] "Burbank Water and Power (BWP) Wind Prestigious National Award for Electric Reliability," April 16, 2021, https://www.burbankca.gov/newsroom/-/newsdetail/20124/burbank-water-and-power-bwp-wins-prestigious-national-award-for-electric-reliability

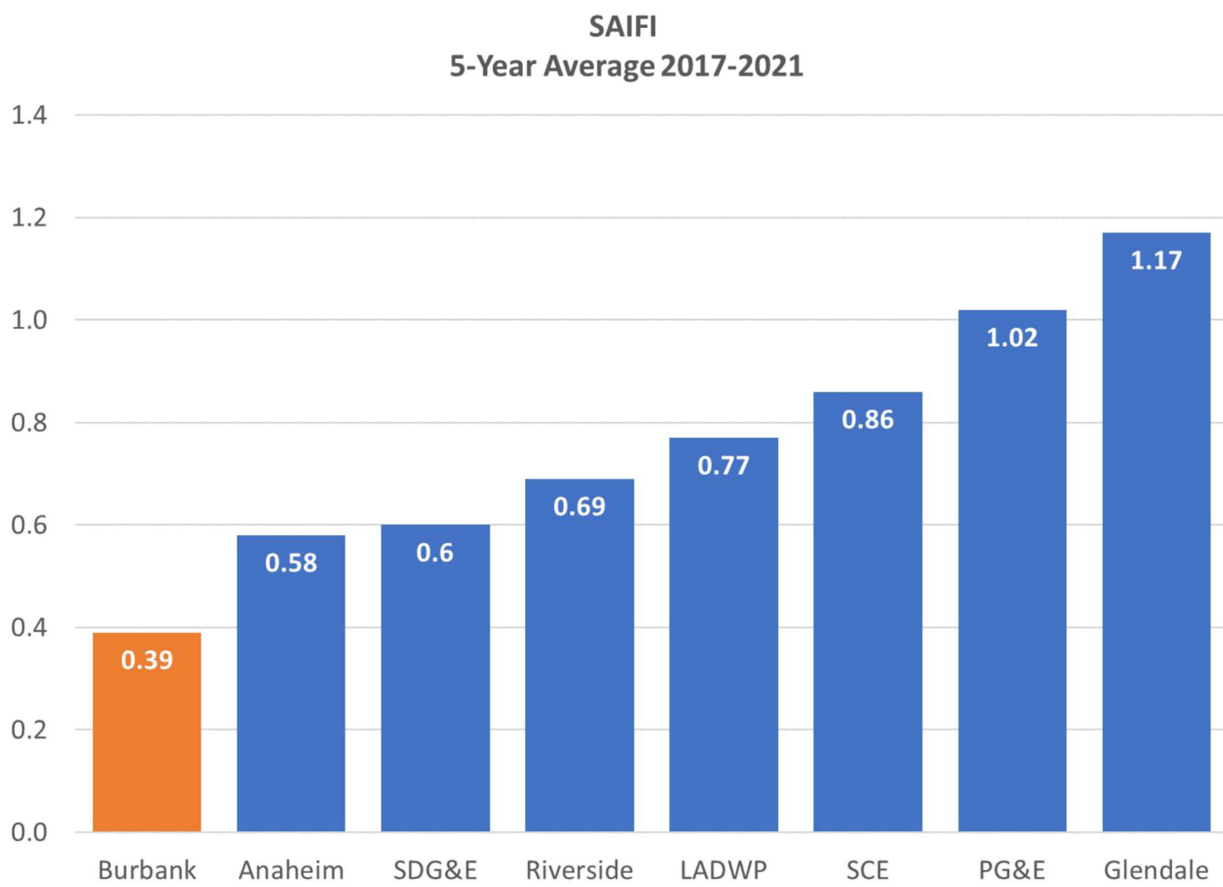

Figure 3-17 SAIFI, 5-Year Average 2017-2021

BWP is one of the most reliable electric utilities in the nation and was recently recognized as a national leader in electric reliability by the American Public Power Association (APPA) earning the Reliable Public Power Provider Diamond level designation. This is the highest designation possible, with BWP scoring 100 out of a possible 100 points.[31]

By having a long-term vision and approach, BWP is strategically addressing these issues, as well as planning methodically to age BWP's assets gracefully while continuing to maintain reliability.

3.8 GREENHOUSE GAS EMISSIONS

3.8.1 GHG CARB Targets

SB 100 also included a statewide target of powering 100% of retail electricity through the use of renewable and zero-carbon resources by the end of 2045. The GHG planning target ranges for

[31] "Burbank Water and Power (BWP) Wins Prestigious National Award for Electric Reliability," April 16, 2021, https://www.burbankca.gov/newsroom/-/newsdetail/20124/burbank-water-and-power-bwp-wins-prestigious-national-award-for-electric-reliability

publicly owned electric utilities were first published in the July 2018 Staff report from CARB. As discussed in Section 3.1.3 above, the September 2023 update to those planning targets included a decrease in the high end of the target planning range for Burbank. The upper end of the range was decreased from 228,000 $MTCO_2e$ to 163,000 $MTCO_2e$.

All of the emissions requirements for planning scenarios examined in Section 2.6 were initially formulated under the higher CARB target planning range. Only after the modeling was completed did CARB finalize its new targets. As such, not every one of the planning scenarios achieves the GHG reductions targeted by CARB for 2030. The scenarios with more aggressive emissions reduction goals or the use of new generation technologies and fuel types see a more rapid decline in forecasted emissions. However, those scenarios contain higher estimated total system and energy costs, or increased risks associated with possible implementation delays inherent in unproven types of clean energy. It must also be noted that all the planning scenarios reach net zero emissions by 2040, five years ahead of the California state goal of 100% clean energy by 2045.

3.8.2 BWP's Green Choice Program

BWP operates a voluntary, opt-in "Green Choice Program" that allows its customer to pay 1.8₵ per kilowatt-hour more than their regular residential electricity rate. The revenue that BWP generates through customer participation in this program are used to purchase renewable energy credits (RECs) from the market. The purchase of RECs helps to offset the participating customer's energy usage with renewable energy and encourages additional renewable energy to be used throughout California.[32]

3.8.3 Burbank's Greenhouse Gas Reduction Plan

Starting in 2013, the City of Burbank has had a Greenhous Gas Reduction Plan (GGRP) that acknowledges the impacts to the climate from human activities. The projected effects of climate change on the residents of the City of Burbank include increased average temperatures, more days with extreme temperatures, an elevated risk of drought, and the possibility of reduced air quality from more frequent wildfires.[33] The GGRP includes long-range policies that focus on: social equity, connectivity with community and resources, structural change, cost effectiveness and financing, outreach and education, and effective greenhouse gas reductions. Within the scope of GGRP related to BWP and the procurement and use and greenhouse gas-neutral energy, a number of strategies are being considered. Among these are:

- Electrification of all new construction,
- Conversion of existing natural gas-fuel HVAC and water heating units to electric heat pumps,
- Increased building energy efficiency through rebate and incentive programs,
- 100% greenhouse gas-neutral electricity generation by 2040.

[32] Burbank Water and Power, https://www.burbankwaterandpower.com/conservation/residential-programs-rebates/green-choice-program
[33] City of Burbank, "Greenhouse Gas Reduction Plan Update," May 3, 2022, https://www.burbankca.gov/documents/173607/0/GGRP+Update+Final_w.App.pdf/

3.9 RETAIL RATES

As a not-for-profit locally owned public utility, BWP's electric rates are designed to recover only the cost of providing highly reliable electric service to its customers while maintaining sound financial standing. The costs to serve BWP's ratepayers include the cost of owning, operating, and maintaining its power plants, power purchases (including renewable energy), transmission and distribution infrastructure, metering and billing systems, customer service and energy efficiency programs, communications equipment, buildings, and transportation fleet. BWP will be modifying its rate structure starting in October 2024. SB 437 requires utilities to discuss transportation electrification customer outreach efforts as well as assess a rate design across the transportation section for electrification. As a result, SB 437 will be addressed in more detail in future IRPs.

3.9.1 Planning Scenario Rate Impact Analysis

Following completion of the modeling for each of the planning scenarios, the results were reviewed and a rate impact analysis was completed by BWP's Rate Manager.

BWP maintains and regularly updates a financial and demand forecast model that looks forward ten years to help plan power supply needs and rate adjustments. Power supply costs make up a substantial portion of the overall annual electric revenue requirement, but there are also other costs related to operations and maintenance, electricity delivery, customer service, and other utility functions. An increase in power supply costs of 5% does not necessarily require a rate increase of 5%, as the rate increase percentage would depend on the amount of the increase for other utility costs – along with the projected sales volume.

Each IRP scenario has two key drivers that determine what the rate impacts will be: annual power supply costs and annual electric sales in MWh. For other utility costs that make up the annual revenue requirement, the analysis assumes typical escalation factors and cost trends inherent in the 10-year forecast model and extends them out to 2047. For example, the 10-year projection assumes that transmission costs will continue increasing by 2.5% per year for the next ten years and this analysis extended this trend through 2047. For each of the seven scenarios, the underlying cost drivers remain constant throughout the analysis period apart from power supply costs and sales volumes, which differentiate the scenarios.

Table 3-8 below, shows the results of the rate impact analysis for each of the seven scenarios. The analysis used two measures to reflect the impact to electric rates and customer bills. The first was the average annual rate increase needed to reach 200 days cash on hand (DCOH) in the final year of the analysis period (2047). The target of 200 DCOH is the midpoint between 160 and 240 DCOH, which is the range recommended by the BWP Financial Reserves Policy approved in 2023. Setting the DCOH target in 2047 can lead to some interim years prior to 2047 having DCOH values less than the minimum threshold and some years well above recommended levels, but the single value provides a useful measure for comparing the rate impact of each scenario as opposed to a series of varying rate adjustments which may be more realistic but harder to compare across scenarios.

The second measure for comparing customer impacts is the bill increase, expressed as the percent increase from current levels to 2047. The bill increase is calculated by applying the average annual rate increase and compounding it through 2047 (after applying the 8.0% increase for 2025). Thus, if the value for this measure were 158%, then a $100 electric bill today would increase to $258 in 2047 (in nominal terms). The 2047 bill increase can be found in column, "Bill Increase 2047 vs. Current."

Table 3-8 shows average annual rate increase for each scenario (in column “Annual Rate Increase”). The increases range from a low of 3.91% for Scenario 6, 10% Lower EV & DEV Demand to a high of 9.49% for Scenario 2, Net Zero by 2030. The third column from the left shows the 2047 bill increases. These have the same scenarios for highest and lowest impacts, with bills for Scenario 6, 10% Lower EV & DEV Demand increasing by 151% and those for Scenario 2, Net Zero by 2030 increasing by 694%. As a point of reference, if rates were increased by 2% per year just to keep pace with general inflation, customer bills in 2047 would only be 67% higher than they are today. The rate increases associated with the IRP are above and beyond the already approved and forecasted rate increases for BWP. For example, we have an approved rate increase of 8% for 2025, so the increase in 2025 would be the approved rate increase of 8%+the rate increase impact from the IRP scenario(s) below. For the Base Case, the increase in 2025 would be 8%+4.03%, for a total of 12.03%.

Table 3-8 Rate Impacts from Planning Scenarios

Scenario #	Scenario Name	Annual Rate Increase (if contracts are signed and are available)	Bill Increase 2047 vs. Current
1	Base Case	4.03%	158%
2	Net Zero by 2030	9.49%	694%
3	SB1020+SMR	4.96%	213%
4	SB1020+SMR w/ 50% DEV &EV Demand	5.57%	256%
5	10% Higher EV & DEV Demand	3.94%	153%
6	10% Lower EV & DEV Demand	4.12%	163%
7	New Transmission & PPAs	4.03%	158%

It is important to note that BWP’s financial forecast model is in annual increments, with each year being the BWP fiscal year (FY) running from July to June. The IRP scenarios are in calendar years (CY) from January to December. The analysis assumed that the “current” time period was FY 2023-24 and calendar year 2024. The Burbank City Council has already approved an 8.0% rate increase to take effect in July of 2024 for FY 2024-25. This 8.0% increase occurs between CY 2024 and CY 2025 in the analysis.

3.9.2 The Ratemaking Process

The ratemaking process is generally composed of three steps: 1) determining the revenue requirement, 2) completing a cost-of-service analysis, and 3) rate design.

3.9.2.1 Revenue Requirements

BWP's electric utility revenue requirement is the total amount of revenue it must recover in order to pay for its operations and maintenance expense, pay-as-you-go (PAYGO) capital, debt service coverage, and reserve requirements. This approach to determining the revenue requirement is sometimes referred to as the "cash-needs" approach, which differs from a rate of return or "utility basis" approach common among investor-owned utilities. BWP's annual revenue requirements are calculated prospectively for five years as part of BWP's annual financial planning and budget process; however, the revenue requirement is only approved one year at a time by the Burbank City Council.

3.9.2.2 Cost-of-Service

The purpose of a cost-of-service study is to ensure that each customer class is paying its fair share of total system costs by determining what it costs to serve each class. In doing so, it greatly informs the rate design process because rates are often designed to recover specific system costs.

A cost-of-service analysis is used to determine each customer class's fair share of the annual revenue requirement and to inform rate design. Each customer class's share of the revenue requirement as determined by the cost-of-service analysis can be referred to as the "class cost of service." BWP generally completes an electric cost-of-service analysis every five years at which time each class cost of service may be updated. The most recent cost-of-service analysis for the electric utility was completed in 2022.[34] BWP has most frequently chosen to use an average or "embedded" cost approach to completing its cost-of-service analyses. An embedded cost-of-service analysis typically involves three steps: 1) functionalization, 2) classification, and 3) allocation. The basis for the analysis is typically a recent year of actual operating results which is called the "test year."

3.9.2.2.1 Functionalization

Functionalization is the process of categorizing the utility's operations and maintenance expense and net assets (original cost less depreciation or "book value") into system functions such as generation, transmission, distribution, and customer service.

3.9.2.2.2 Classification

Classification is the process of classifying costs by function according to how those costs vary. For example, bulk power supply costs tend to vary based on energy throughput, while distribution capacity costs tend to vary based on peak demand. In these cases, bulk power supply costs are classified by the energy classification type while distribution capacity costs are classified by the peak demand classification type. Each classification type describes units of service for all customer classes. Common classification types include energy, demand, customers, and meters.

3.9.2.2.3 Allocation

Allocation is the process of assigning the classified costs to customer classes in proportion to each class's share of the total units of service for each classification type. For example, all costs that are classified by the energy classification type are allocated among the different customer classes based on each class's share of the total energy units of service measured in kilowatt-hours. This class cost

---

[34] City of Burbank, Burbank Water and Power, Staff Report, dated June 6, 2023, https://www.burbankca.gov/documents/20124/0/SR+-+Public+Hearing+for+Rates+Increase.pdf

of service is the total cost allocated to each class for each classification type. BWP currently has five major customer classes: residential, small commercial, medium commercial, large commercial, and extra-large commercial. Street lighting is also included as a separate class.

Table 3-9 2022 Class Cost of Service Study Results

Customer Class	Cost of Service Results (%)
Residential	36.6%
Small Commercial	8.5%
Medium Commercial	18.9%
Large Commercial	16.8%
Extra Large Commercial	18.8%
Street Lighting	0.4%
Total	**100.0%**

3.9.2.3 Rate Design

Once the class cost of service is determined for each customer class, rates can be designed to recover that amount. Rate design may vary between and within the major customer classes depending on, for example, the type of residential customer (standard, lifeline, or electric vehicle owner), or the service voltage (primary or secondary). Rate design may also vary due to differing objectives for certain classes or subclasses and/or due to billing system constrains. A detailed discussion of BWP's current rates in presented in the Current Electric Rates section below.

3.9.3 Appropriate Price Signals

Beyond ensuring each customer class pays its fair share for operating and maintaining the electric utility, BWP believes its rates should send appropriate price signals to customers to help them understand – and respond to – how the utility's costs vary overall. Naturally, the more energy customers use, the most costs are incurred. However, when and how customers use more energy greatly impacts which costs are incurred for BWP and how much. BWP believes electric rates should be designed to reflect the impacts of when and how costs are incurred.

3.9.4 Current Electric Rates

BWP currently has five major customer classes: residential, small commercial, medium commercial, large commercial, and extra-large commercial. Residential service includes service for lifeline customers and electric vehicle owners. Lifeline customers are senior and/or disabled customers that are eligible for discounted electric rates. Electric vehicle owners may elect to receive service under BWP's optional electric vehicle owner rate schedule which offers lower energy rates during off-peak periods. This rate schedule is discussed in further detail below.

BWP's commercial customers are assigned one of the four commercial classes based on their monthly demand – the maximum instantaneous 5- or 15-minute interval reading per billing period. Commercial customers are assigned to classes as summarized below.

Table 3-10 Commercial Customer Classes for Rates

Commercial Class	Monthly Demand
Small	Less than 20 kVA
Medium	Between 20 kVA and 250 kVA
Large	Between 250 kVA and 1,000 kVA
Extra Large	More than 1,000 kVA

Table 3-11 Types of Charges Applicable to Major Customer Classes

	Energy Charges		Fixed Monthly Charges		Demand Charges		
Customer Class	2-Tier Inclining Block Energy Charges*	Time of Use Energy Charges	Customer Service Charge	Service Size Charge	Demand Charge	Distribution Demand Charge	Reliability Services Demand Charge
Residential	X		X	X			
Small Commercial		X	X				
Medium Commercial		X	X		X		
Large Commercial		X	X			X	X
Extra-Large Commercial		X	X			X	X

*Includes Energy Cost Adjustment Charge (ECAC)

Each customer class is subject to either a "2-part tariff" or a "3-part tariff." Residential customers and small customers are subject to 2-part tariffs in which they pay a monthly fixed service charge and per-kWh energy charges. Medium, large, and extra-large commercial customers are likewise subject to monthly service and energy charges; however, they are also subject to per-kVA demand charges. Each rate, or "part," is generally designed to recover specific costs, which are revealed by the cost-of-service analysis.

3.9.5 Energy Charge

All of BWP's metered customers are subject to per-kWh energy charges, which are inclusive of the energy cost adjustment charge (ECAC). The ECAC is an energy charge that specifically recovers the cost of variable power supply costs including, but not limited to, fuel and purchased power expenses. BWP currently employs two types of energy charges: 2-tier inclining-block and time-of-use.

3.9.5.1 2-Tier Inclining-Block Energy Charges

Residential service customers, except for those customers that elect the optional electric vehicle rate, are subject to 2-tier inclining-block energy charges. 2-tier inclining-block energy charges offer energy at two inclining or increasing rates. The first, cheaper rate, applies to consumption up to the upper bound of the first "block" or tier. The second, more expensive rate, applies to incremental consumption above the first block or tier. For standard residential customers, the upper bound of the first block is 300 kWh. For residential lifeline customers, the upper bound of the first block is 400 kWh. The purpose of inclining-block energy charges is to encourage conservation, as higher consumption is subject to a higher rate.

3.9.5.2 Time-of-Use Energy Charges

Time-of-Use (TOU) energy charges are energy charges that vary based on the time of day, day of week, month of year, and observance of holidays. Currently, all commercial customers are subject to time-of-use energy charges. This rate schedule is designed to shift energy use from high-cost periods, such as in the evening between 4pm and 7pm, to low-cost periods.

Table 3-12 Time Periods for Time-of-Use (TOU) Rates

	Summer		Non-Summer	
Time	Weekday	Weekends & Holidays	Weekday	Weekends & Holidays
Midnight to 8am	Off	Off	Off	Off
8am to 4pm	Mid	Off	Mid	Off
4pm to 7pm	On	Off	Mid	Off
7pm to 11pm	Mid	Off	Mid	Off
11pm to Midnight	Off	Off	Off	Off

Table 3-13 Time Periods for Time-of-Use (TOU) Rates for Residential Electric Vehicle Owners

Time	Summer	Non-Summer
Midnight to 8am	Off	Off
8am to 4pm	Mid	Mid
4pm to 7pm	On	Mid
7pm to 11pm	Mid	Mid
11pm to Midnight	Off	Off

The summer season is from June 1 through October 31, and the non-summer season is from January 1 through May 31, and November 1 through December 31. Observed holidays are New Year's Day (January 1), Presidents' Day (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

BWP believes that time-of-use rates are a useful demand side management tool for reducing overall system costs. TOU rates can encourage customers to change their consumption patterns such that they reduce the utility's need to procure energy and capacity during the most expensive periods of the year. TOU rates can also encourage customers to shift their consumption to periods of the year when energy (often renewable) and capacity is in excess. These changes in consumption patterns can be beneficial to both the customer and BWP in terms of cost savings.

TOU rates will become an increasingly important tool for BWP as it continues to integrate more intermittent renewable resources. BWP believes in the potential for residential customers to respond to TOU rates, lowering their bills and decreasing the utility's cost to serve customers on a long-term basis.

3.9.6 Fixed Monthly Charges

Fixed monthly charges are generally designed to recover the cost of customer service and billing. For residential customers, they may also take the form of a service size charge which is designed to recover secondary distribution system costs.

3.9.6.1 Service Size Charge

The service size charge recovers customer-specific system costs, including the cost of wires and transformers and is determined by the customer's electrical panel size and the number of homes or buildings sharing a single transformer.

Customers are categorized as follows for service size charges:

- Small: Service Location with two or more meters per service drop and does not meet the definition of Large; typically multifamily residential.
- Medium: Service location with one meter per service drop and does not meet the definition of Large; typically single family residential.
- Large: Service with panel size greater than 200A.

3.9.6.2 Customer Service Charge

All customers are subject to a fixed monthly customer service charge with the exception of residential lifeline customers. This charge ranges from $12.07 (FY 2023-24) for residential basic service rate customers to $122.51 (FY 2023-24) for extra-large commercial customers. Note that for commercial customers, the monthly customer service charge may vary depending on whether the customer is unmetered, has single-phase service, or three-phase service.

3.9.7 Demand Charges

Demand charges are typically designed to recover capacity cost associated with transmission, distribution, and/or generation. The simple demand charge, which is designed to recover all of these costs only applies to medium commercial customers on a per-kVA basis. Two separate demand charges apply to large and extra-large commercial customers as discussed below.

3.9.7.1 Demand Charge – Medium Commercial

Medium commercial customers are subject to a simple demand charge, which is designed to recover the cost of distribution, transmission, and generation capacity. This charge is measured on a per-kVA basis.

3.9.7.2 Distribution Demand Charge

The distribution demand charge is a per-kVA demand charge that applies to both large and extra-large commercial customers. It is designed to recover distribution capacity costs. It is measured on an all-hour or "non-coincident peak" (NCP) basis, meaning that the demand reflects the maximum interval read of all reads during a given billing period. This is in contract to a "coincident peak" (CP) basis for demand measurement, which only measures demand during a subset of monthly hours when the entire system is believed to peak.

3.9.7.3 Reliability Services Demand Charge

The reliability services demand charge is also a per-kVA demand charge that applies to both large and extra-large commercial customers. It is designed to recover generation capacity or "peaking costs." It is also measured on an NCP basis.

3.9.8 Electric Rate Comparison

BWP's residential electric rates remain among the lowest in the region including other municipal utilities, as well as investor-owned utilities.

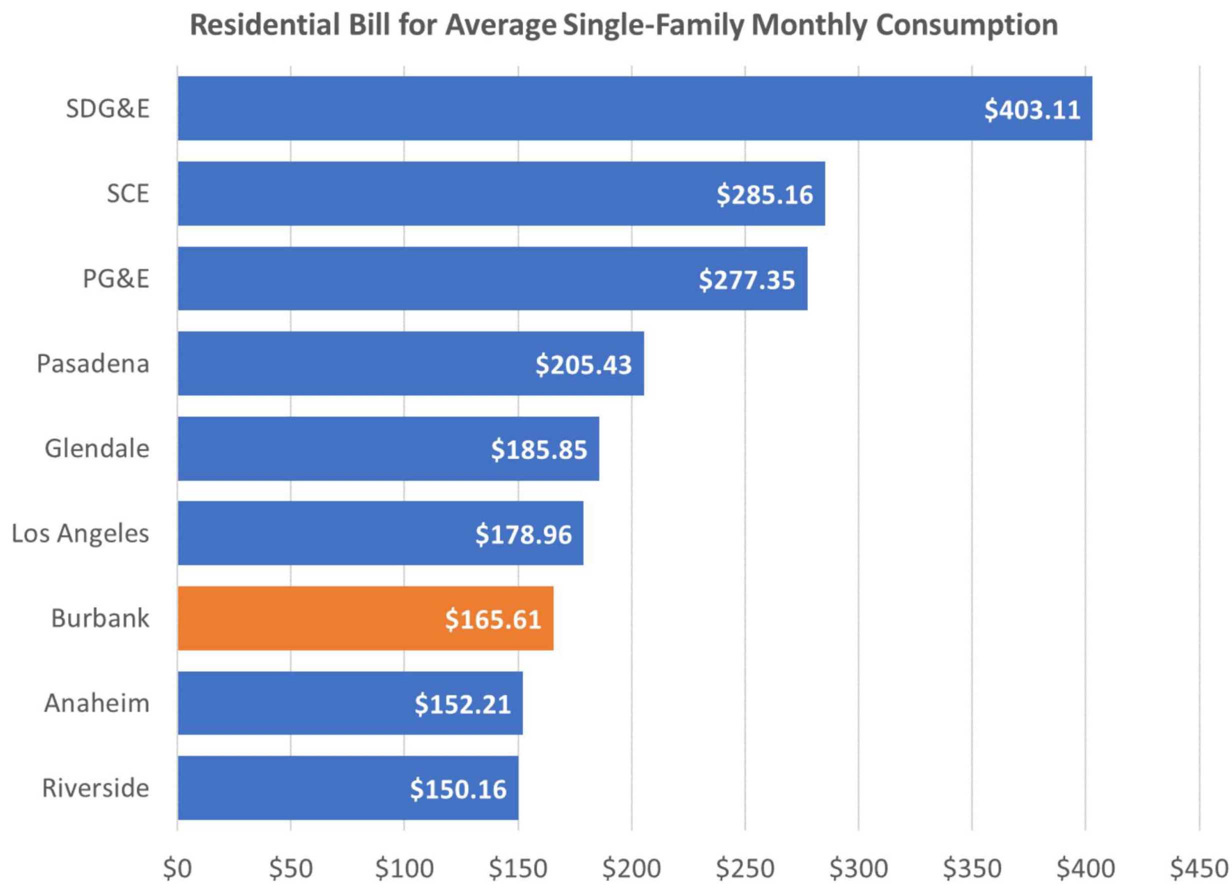

Figure 3-18 Residential Bill for Average Single-Family Monthly Consumption[35]

All fees and charges are brought before the City Council for approval on an annual basis.

BWP has also developed short-term as well as long-term energy procurement strategies to reduce price risks and volatility. These strategies are monitored by BWP management using the Energy Risk Management Policy, originally adopted in 2004 and amended in April 2009 and December 2017. Under the Energy Risk Management Policy, the Risk Oversight Committee was formed and meets regularly to discuss the power supply risks, market conditions, and transactions needed to maintain reliable and affordable rates for Burbank.

[35] Burbank Water and Power, FY 2023-23 & FY 2024-25 Proposed Budget, April 6, 2023 presentation, https://www.burbankwaterandpower.com/images/budget/april-2023-budget-files/Proposed%20Utility%20Fiscal%20Year%202023-24%20and%202024-25%20Budgets%20for%20BWP%20Board.pdf

3.10 TRANSMISSION SYSTEM RESOURCES

Power transmission is the delivery of energy from its place of generation, purchase, or sale to the distribution system that takes it to meet demand. Burbank has ownership in or contractual entitlements to numerous regional transmission facilities. Transmission lines bring in electric energy to meet demand and BWP uses its contractual and ownership rights to deliver the electricity it generates and purchases to customers in Burbank.

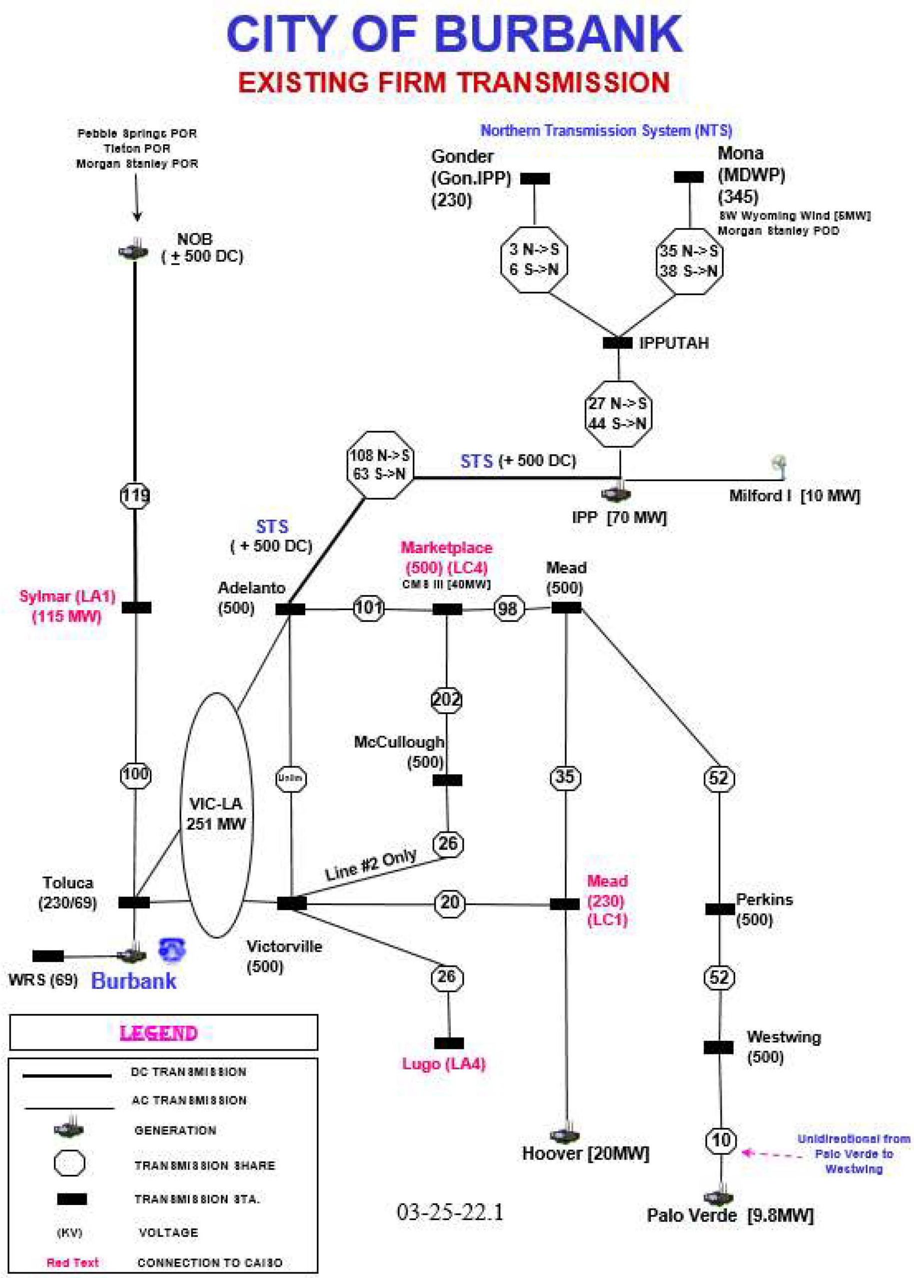

Figure 3-19 Burbank's Existing Firm Transmission

3.10.1 History of BWP's Transmission Rights

The utility business has changed tremendously over the years. Historically, BWP has worked with the SCPPA and other entities to participate in major new transmission projects so that BWP can move power from generation facilities, or other entities, throughout the western United States.

Over time, BWP has focused on engaging in new transmission contracts and on finding advantageous power resources or supplies that help keep electric rates low. SCPPA was formed in 1980 to help finance these transmission projects for municipal utilities to leverage economies of scale and keep costs low. BWP worked with other participants through SCPPA to jointly build major transmission lines such as Mead-Phoenix and Mead-Adelanto. Since BWP helped build those projects, it has rights to schedule and move power over those transmission lines.

These transmission rights are adequate to serve BWP's current energy needs. They also enable BWP to participate in the wholesale power market. However, as more renewable energy is added and/or replaced, it may be necessary to acquire additional transmission service or participate in the development of new transmission lines.

BWP can also enter into swaps and other agreements to use a third party's transmission assets. In those cases, BWP might purchase renewable energy from a distant power plant and swap it to a third party, which would then deliver substitute energy to BWP from closer to Burbank. In that sort of arrangement, the third party also absorbs the intermittency of that renewable energy source, if any. Arrangements like those are another method of acquiring resources in the most cost-effective manner.

3.10.2 Planned Transmission Upgrades and Additions

3.10.2.1 Southern Transmission System

The Southern Transmission System (STS) currently consists of a high voltage direct current (HVDC) line from the IPP site near Delta, Utah to Adelanto, California. This line currently carries the baseload output of the IPP coal plant. As discussed in Section 2.5.4, the IPP coal plant is scheduled for retirement in 2025 and will be replaced with natural gas-fired generation. BWP's new contract with IPP begins in 2027 and was entered into, in part, to secure future transmission rights on the STS. Use of those STS transmission rights will be key to accessing additional renewable energy resources located outside of Burbank. Prior to the renewal of the IPP contract in 2027, BWP will maintain a 4.49% share of the STS capacity, equal to 107.95 MW. Per the terms of the contract renewal, from 2027 through 2077, BWP will have a 4.2% share of the transmission capacity on the STS, equal to 101.4 MW.

3.10.2.2 Transmission Expansion Considered Within the IRP

The production cost model created for the Base Case in this IRP was optimized around the existing transmission system that serves Burbank. As such, no transmission expansion was either "hard-wired" into the model or included as a possible expansion project for the model to choose. In the Base Case, all demand on the BWP system through 2047 could be met with the transmission capacity that already exists. However, it should be noted that by the end of the planning period, that the existing transmission capacity was at times fully utilized. Demand growth beyond what was forecast for 2047 could result in the need to acquire additional transmission rights or to physically expand the capacity of the transmission system that delivers power to Burbank. Where transmission expansion was included within the other planning scenarios, it has been noted. See Section 2.6 for scenario specific information.