DOCKETED

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Filer:	Mandip K Samra
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Figure 2-5 shows how Base Case portfolio's capacity mix changes over the planning horizon. Intermountain is converted from coal to natural gas in mid-2025 which causes the capacity dip in 2025-2026 due to a lower BWP ownership share after the conversion. Decreases in wind capacity in the 2020s is due to contracts expiring for Milford Wind Corridor I and Pebble Springs. The decrease in geothermal capacity in 2033 is due to BWP's contract with Don A. Campbell expiring. New resources were allowed to be constructed within the capacity expansion model starting in 2027. That is the earliest available procurement date for new resources that BWP could make considering resource availability and interconnection queue delays. Between 2027 and the mid-2030s the two primary types of resources built are new solar and geothermal units with the exception being a ~3MW solar plant paired with a storage facility going in-service in 2027.

The Inflation Reduction Act (IRA) is a key driver in resource selection. The IRA has increased the economic incentive for solar, wind, geothermal, energy storage, and nuclear technologies. The Base Case portfolio selects solar aggressively in the short term due to its relatively competitive capital cost, zero fuel cost, and IRA Production Tax Credits (PTCs). Another contributing factor to solar buildout is that BWP does not currently have a high level of solar penetration; therefore, the incremental value of solar is higher in the short term. Solar growth slows down post-2035 due to solar generation starting to saturate which results in a lower incremental value for additional solar resources. As solar penetration increases, the time at which the net demand peak occurs is pushed towards hours where solar generation is lower. In this context, the net demand is the total demand minus the contributions from wind and solar generation. As the net demand peak moves into parts of the day when solar energy's contributions begin to decrease, the incremental value of solar energy decreases and other types of generation become relatively more valuable. Furthermore, as electric vehicle adoption increases, energy demand will shift towards the night/early morning hours when vehicle owners are charging their vehicles and solar generation is low or zero. A key driver in the timing of solar and wind buildout is the IRA. Solar and wind resources are built during the years where PLEXOS' capacity expansion logic can take advantage of the IRA's PTCs for renewable resources. In the later years of the planning horizon, the IRA tax credits will have expired and solar and wind resources lose a material economic incentive relative to other technologies.

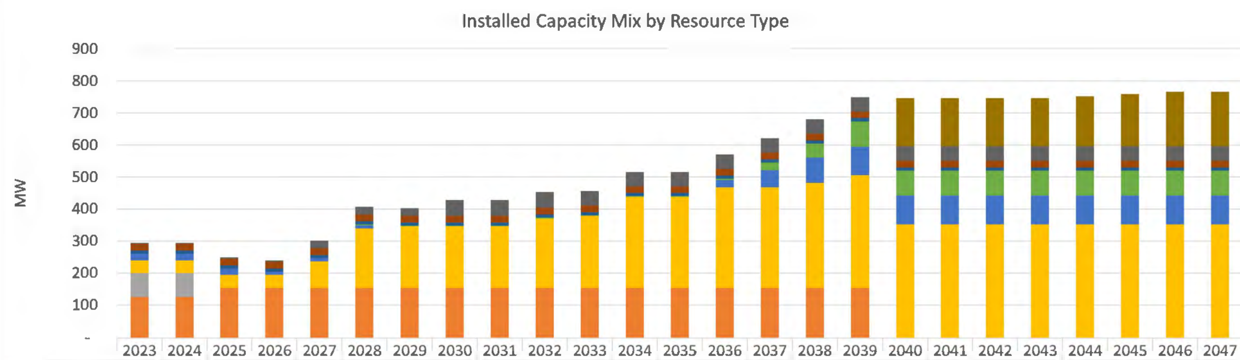
Energy storage plays an important role in the Base Case portfolio due to its ability to shift renewable energy to different hours to meet demand around the clock. Battery Energy Storage Systems (BESS) appear in the portfolio beginning in 2027; however, its major period of growth is between 2033-2039 when it can take advantage of higher levels of intermittent generation. BESS facilities are able to store energy during periods of surplus supply and then discharge that energy during hours of peak load when it is needed. Another benefit of building BESS during the 2030s is that the assets will still be able to capture the benefits from ITC from the IRA.

As solar generation saturates, wind turbines can become preferable to solar power plants. PLEXOS starts building wind resources in 2036 to help diversify the portfolio and complements the hourly generation profile for solar. Wind and solar energy can complement each other because each technology has different strengths related to their expected generation profiles. For example, wind generation typically peaks in the overnight hours and while solar generation will peak during the day.

Geothermal buildout was guided by what BWP is currently seeing in the market and by what they can realistically procure based on the interconnection queue data. BWP is currently pursuing geothermal resources in Utah which drove the buildout in the model.

All existing natural gas resources are converted to run on hydrogen in 2040. This is needed to achieve 100% zero-carbon resources by 2040. This conversion includes Magnolia, IPP and Lake One. The current cost assumption is that BWP will only have to pay its share of the conversion costs; however, if other co-owners do not approve the conversion, the cost could be much higher for BWP. In addition to the natural gas-to-hydrogen conversions, new hydrogen-fueled combustion turbines are built between 2040 and the end of the planning horizon. Hydrogen-fueled combustion turbines are Zero Emitting Load Following Resources (ZELFRs) that decreases the amount of market purchases required and increase system reliability.

It will be important for new technologies, such as hydrogen-fueled turbines/engines, to come to fruition and be built at the scale necessary to meet decarbonization goals. If hydrogen or other emerging ZELFRs do not materialize, the cost of deep decarbonization will increase significantly. It would require significant over-procurement of renewables and storage to ensure BWP can meet real-time demand around the clock. Lack of ZELFR technology would also increase the risk of not being able to serve load due to renewable energy output variability and demand forecast errors.



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RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151	151	151	156	163	170	171
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
BESS	-	-	-	-	-	3	3	3	3	3	3	3	3	3	24	42	79	79	79	79	79	79	79	79	79
Wind	20	20	20	10	10	10	-	-	-	-	-	-	-	23	53	79	89	89	89	89	89	89	89	89	89
Solar	40	40	40	40	83	185	191	191	191	216	224	284	284	315	315	329	352	352	352	352	352	352	352	352	352
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	-	-	-	-	-	-	-	-

Figure 2-5 Base Case Portfolio Capacity Mix

Figure 2-6 shows the generation mix for the Base Case portfolio. The generation mix shows coal generation going away mid-2025, and natural gas generation ramping up in the short-term. As the 100% clean energy goal approaches, natural gas generation declines until the existing turbines are converted to burn hydrogen in 2040. Increasing solar and geothermal generation helps meet load growth, lower market purchases, and lower CO_2 emissions through lower gas generation. Post-2040 hydrogen generation is increasing to keep up with load growth.

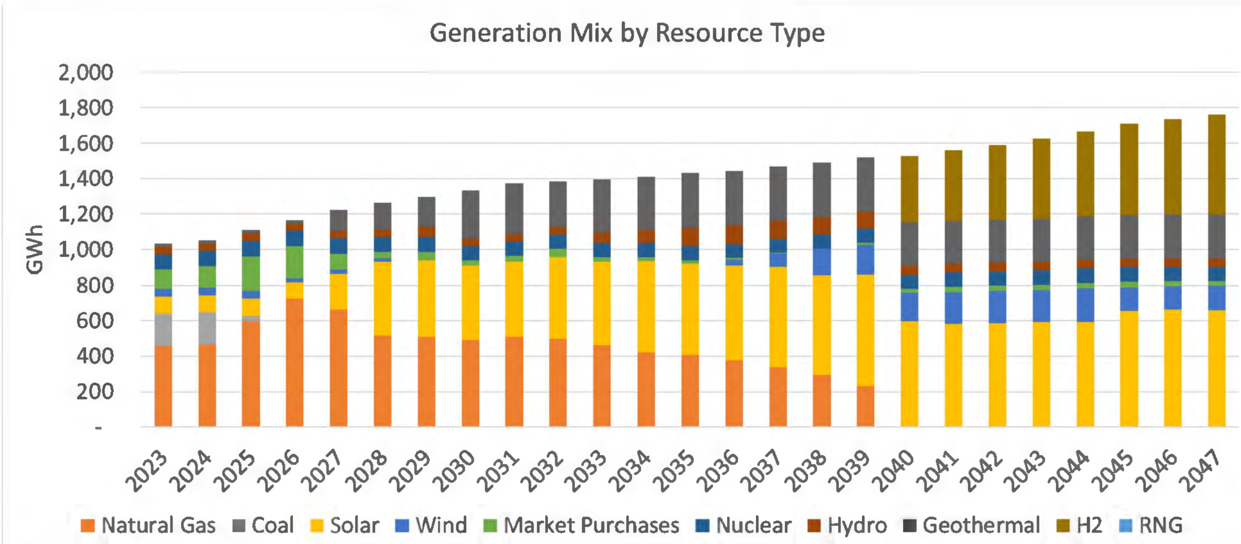


Figure 2-6 Base Case Portfolio Generation Mix

Figure 27 shows the Base Case Portfolio's annual RPS achievement and target. The RPS target comes from SB100. Additional REC Purchases are required in the short term until BWP can procure new renewable resources. The Base Case portfolio is able to meet the 60% RPS requirement in 2030 without needing to purchase additional RECs and continues to procure renewables to ensure load growth can be met. There is a significant jump in RPS percentage achieved in 2040 which surpasses 100% RPS. The reason for this is that the natural gas units convert to hydrogen and the solar generation that is being used to create hydrogen through electrolysis is counted towards the RPS percentage. This solar generation is not modeled as a load serving generator in the model but rather is being used to calculate the hydrogen fuel price forecast. In other words, the solar generation associated with hydrogen fuel production is being counted towards RPS compliance while the load associated with the electrolysis process was not counted towards retail sales.

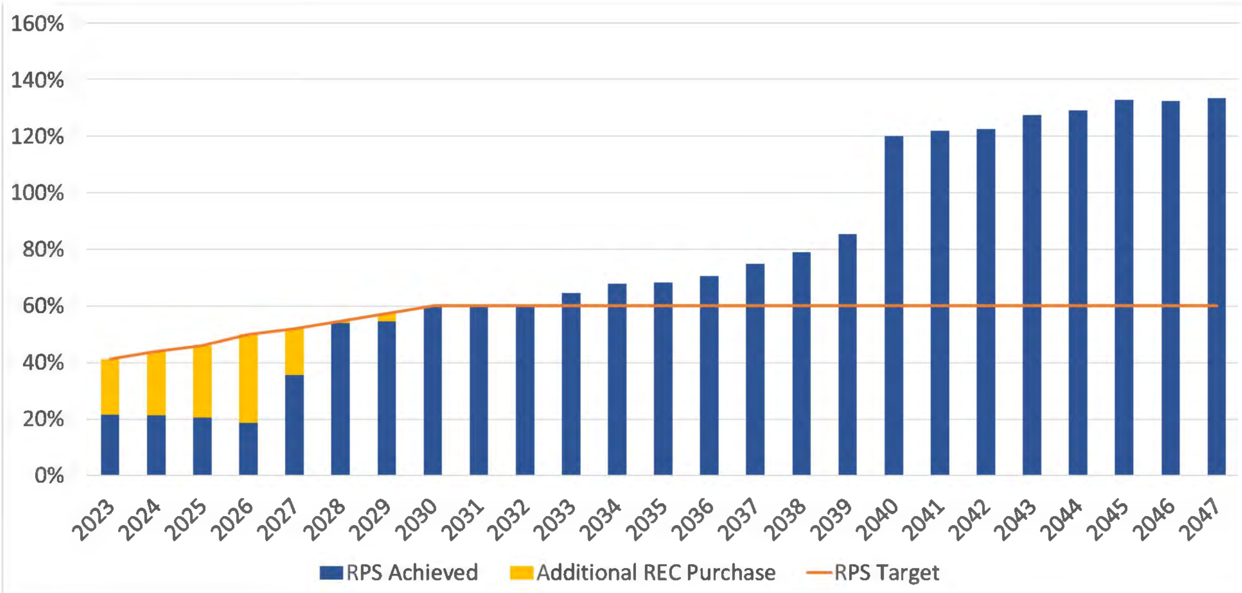


Figure 2-7 Base Case Annual RPS Percentage

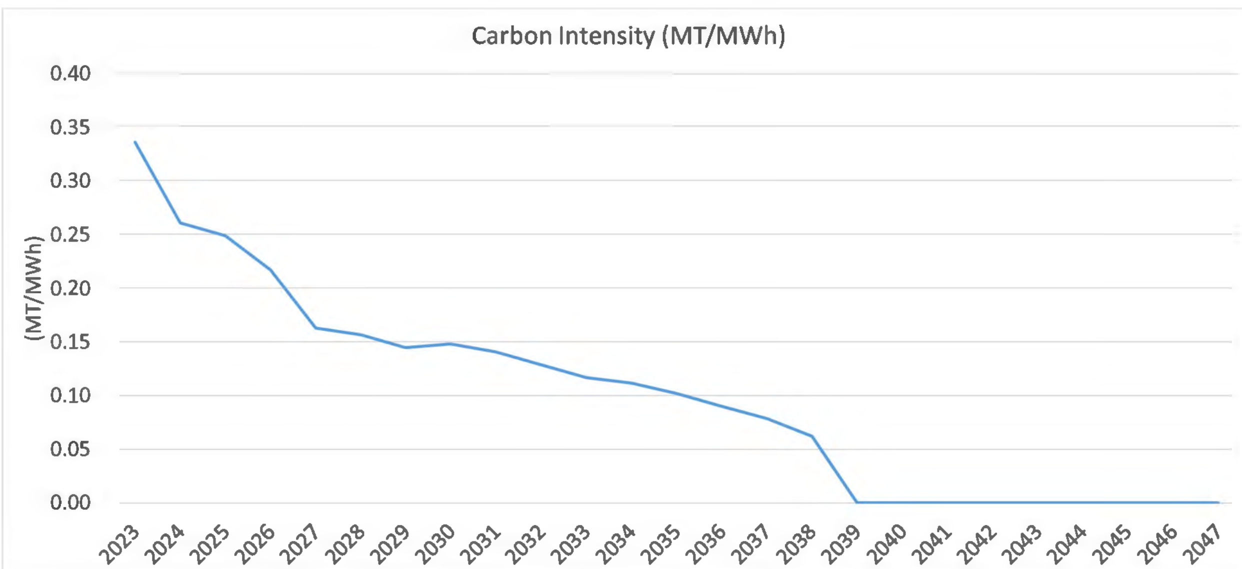


Figure 2-8 Base Case Carbon Intensity

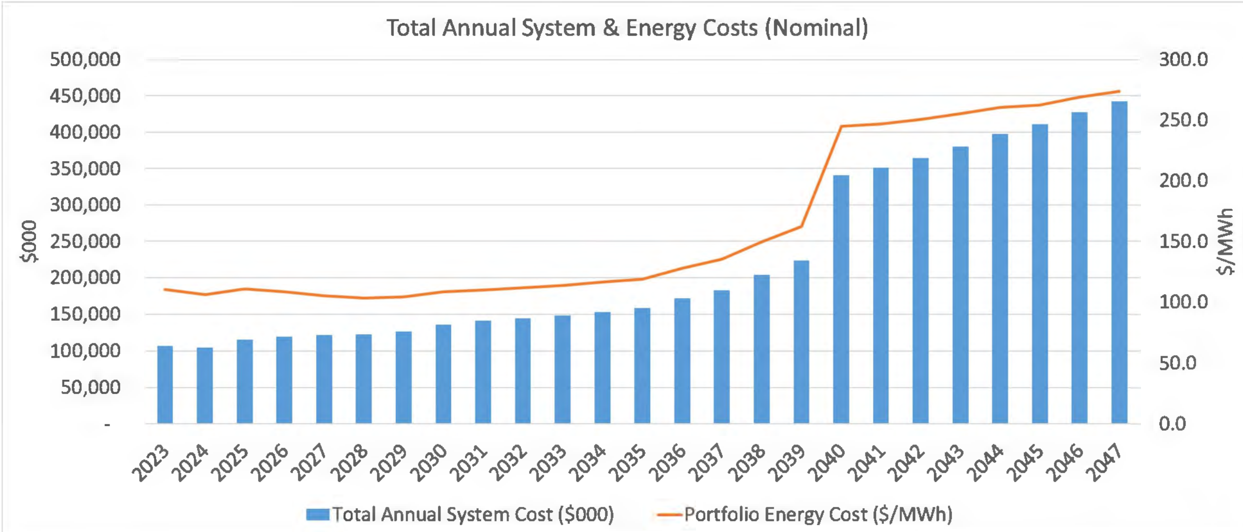


Figure 2-9 Base Case Total System and Energy Costs

2.6.2 "Net Zero by 2030" Planning Scenario

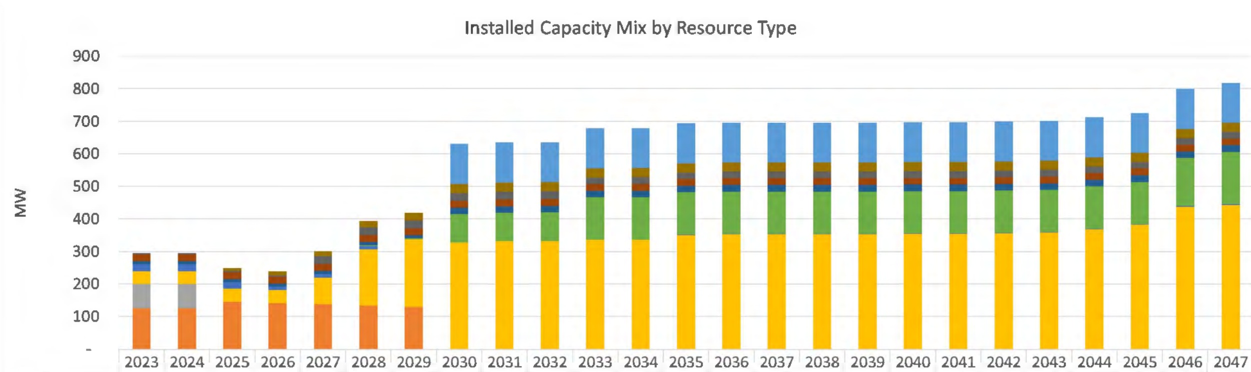
The Net Zero by 2030 planning scenario examines the effects of significantly accelerating decarbonization efforts. In this scenario a requirement to meet Burbank's energy needs through zero-carbon resources by 2030 was added to the Base Case model. Here, it should be noted that Scope 3 emissions from market energy purchases are not included when calculating that zero-carbon requirement. In a change in assumptions from the Base Case, it was assumed that energy from an SMR would be available starting in 2030.

To reach the early decarbonization goals, Magnolia and Lake One had to convert from conventional natural gas to RNG starting in 2030. This differs from the Base Case in which those units were converted from natural gas to hydrogen fuel starting in 2040. The early conversion of Magnolia, Lake One, and IPP to net zero carbon fuels like RNG and hydrogen is predicated on sufficient quantities of those fuels being available at the times they are needed. Hydrogen conversion for Magnolia and Lake One was not available in 2030 because it is unlikely that hydrogen infrastructure will be sufficient by that time to maintain healthy capacity factors at these existing locations. Fuel & portfolio diversity is going to play a key role in decarbonizing the electric sector and so IPP was selected to be the existing unit to convert to hydrogen. Within this scenario, IPP converts to natural gas in 2025 and begins blending hydrogen fuel that same year. "Blending hydrogen" meaning that the unit is burning a blend of hydrogen and natural gas fuel. IPP fully converts to run on hydrogen by 2030 to meet the net-zero goal.

Another diversifying asset in this portfolio is the SMR PPA that is assumed to become available in 2030. SMRs offer baseload clean energy and could be a hedge against any uncertainties surrounding hydrogen fuel availability. Likewise, RNG, hydrogen, and batteries could hedge against the uncertainties surrounding SMR technology risks and project timelines. This portfolio built ~80MW more BESS resources compared to the Base Case to help shift clean energy to hours where the system needs it the most. It is important to note that standalone BESS resources do not have to only charge from renewables but can also charge from baseload clean energy resources like SMRs.

RNG, hydrogen, BESS, and SMR resources play a key role for ensuring system reliability in the "Net Zero by 2030" planning scenario. Achieving 100% clean energy with only intermittent renewables and batteries would result in over-procurement of those resources and additional system costs associated with that significant buildout. ZELFRs like SMRs or power plants fueled by RNG or hydrogen help mitigate risks associated with intermittent resource generation forecast errors and help ensure system reliability. However, this planning scenario would be very challenging to implement by 2030 given the lack of RNG contracts on the market and the tight timeline to convert IPP to run on 100% hydrogen by 2030.

The actions necessary to reach decarbonization goals early resulted in a total system cost over the study period that is significantly higher than the Base Case and is the highest cost portfolio in the IRP modeling analysis. The system cost drastically increases in 2030. This increase in system cost is mainly driven by two key factors. Firstly, there are significant transmission costs associated with upgrades needed to transfer enough clean energy around the clock by 2030. In comparison, the Base Case had these transmission costs incurred in 2040. Secondly, there are significant costs associated with capital investment to achieve Net Zero by 2030. SMRs are capital intensive investments, and that capital cost is being passed to BWP through variable costs in the modeled PPA agreement. Also, BWP's assumption is that they would be responsible for the total all-in cost to convert Magnolia to RNG which includes both fixed and variable costs during and post-conversion. This assumption implies that there would not be enough support from the other co-owners for the conversion that BWP would have to pay to convert the entire plant in 2030 as well as the variable operating costs associated with the plant thereafter. System cost could be materially lower if there would be enough support from other co-owners to convert the plant.



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RNG	-	-	-	-	-	-	-	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123
H2	-	-	8	12	16	20	24	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Geothermal	4	4	4	4	24	24	24	24	24	24	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
BESS	-	-	-	-	-	3	3	87	87	88	130	130	130	130	130	130	130	130	130	130	130	130	130	148	161
Wind	20	20	20	10	10	10	-	-	-	-	0	1	1	1	1	1	1	1	1	1	1	1	2	2	2
Solar	40	40	40	40	83	173	207	328	332	332	336	336	350	353	353	353	353	354	354	356	358	368	382	437	443
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	146	142	138	134	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 2-10 "Net Zero by 2030" Planning Scenario – Installed Capacity

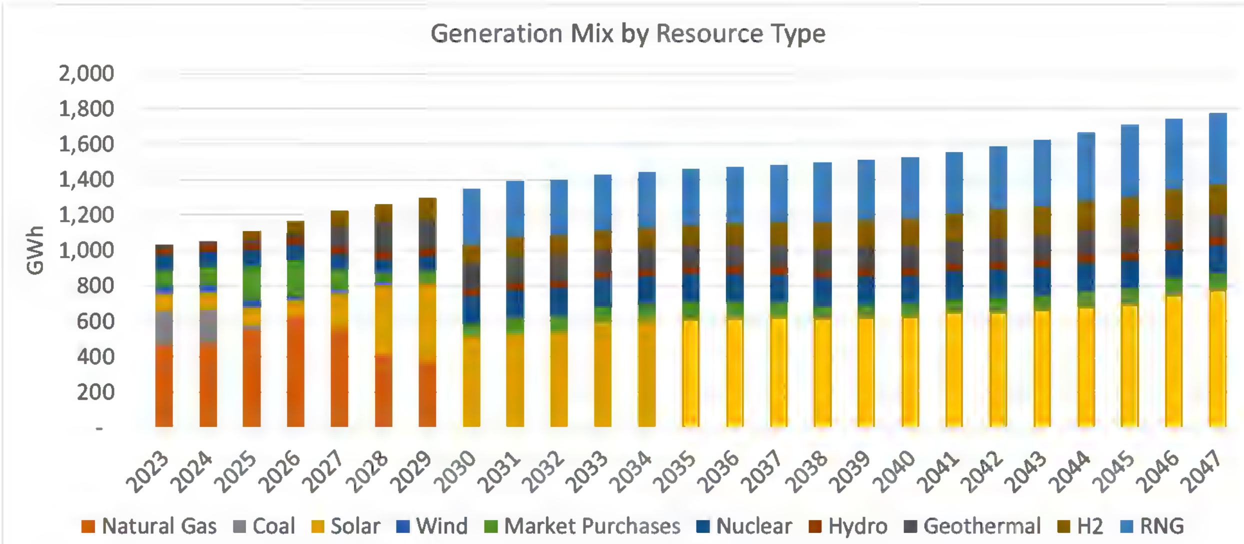


Figure 2-11 "Net Zero by 2030" Planning Scenario – Generation Mix

Figure 2-12 Net Zero by 2030 Scenario – RPS Percentage

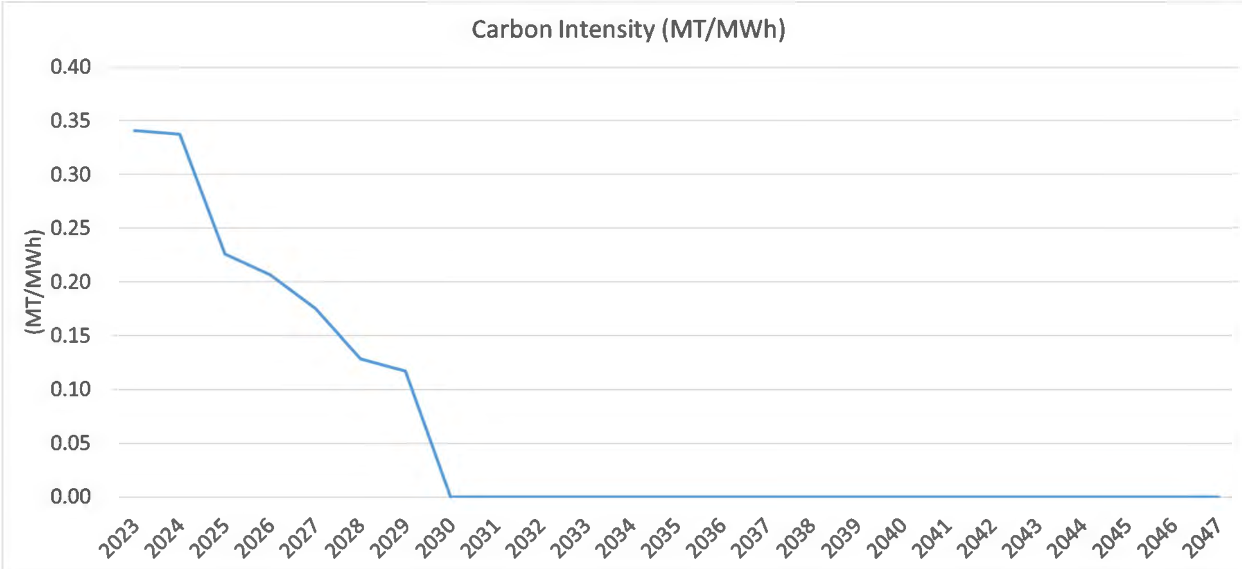


Figure 2-13 Net Zero by 2030 Scenario – Carbon Intensity

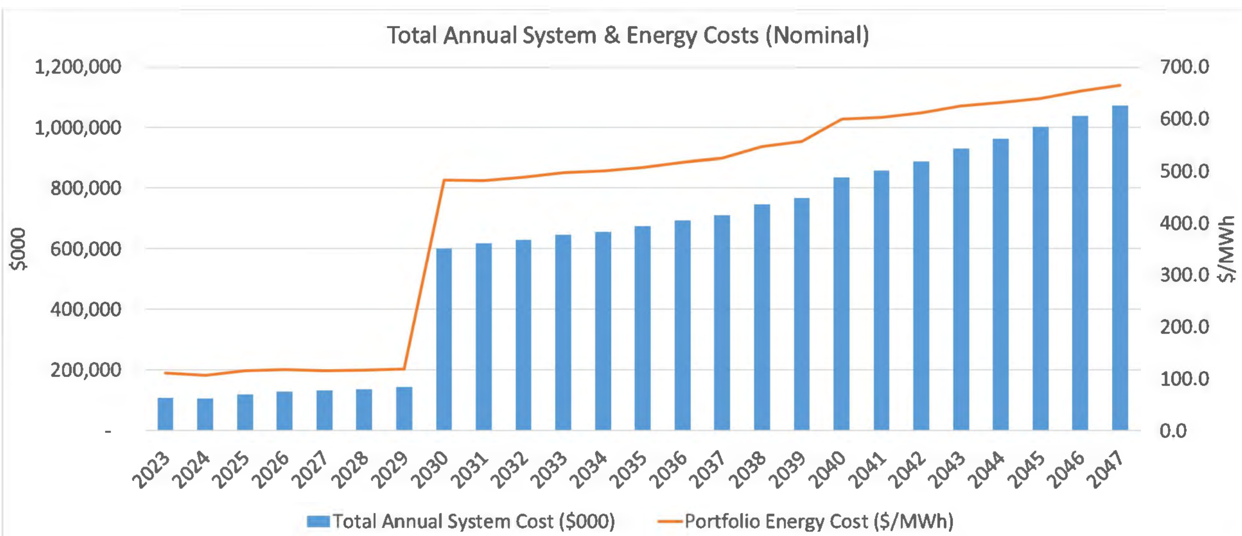


Figure 2-14 "Net Zero by 2030" Planning Scenario – Total System and Energy Costs

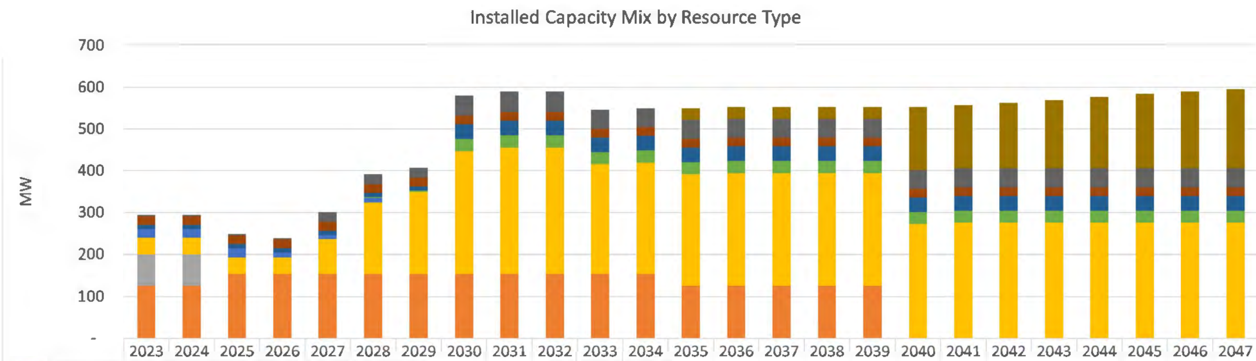
2.6.3 "SB1020+SMR" Planning Scenario

The SB1020+SMR planning scenario incorporates the interim targets added by The Clean Energy, Jobs, and Affordability Act of 2022 (SB1020). The updated model for this scenario includes a 60% RPS requirement in 2030 that shifts to a linearly increasing 90% clean energy requirement by 2035. The 95% clean energy requirement for 2040 and 100% zero-emissions requirement in 2045 used in the Base Case remain unchanged.

This planning scenario includes the assumption that BWP will enter into a purchased power agreement for 25 MW of capacity from a SMR starting in 2030. Additionally, IPP is assumed to fully convert to burning hydrogen instead of natural gas starting in 2035 as opposed to 2040 in the Base Case.

With the addition of baseload ZELFR resources such as SMR and the hydrogen conversion at IPP, the need for renewables and storage is less relative to the Base Case. This scenario does not include any new wind energy besides that which was already being provided by the preexisting wind power contracts at Milford and Pebble Springs. Total solar energy buildout by the end of the planning period was ~76MW less when compared to the Base Case. With fewer intermittent renewable resources needed due to ZELFR resources, there is less intermittent generation available for storage assets to shift to meet system needs. Therefore, the total amount of stand-alone battery storage needed in this scenario is also reduced.

As compared with the Base Case, the SB1020+SMR scenario results in an accelerated decrease in carbon emissions due to the earlier conversion of IPP to hydrogen and the inclusion of the zero-carbon energy from the SMR contract. Total carbon emissions over the study period are 14% lower than in the Base Case, However, this scenario also has a total system cost over that same period that is materially higher.



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RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	28	28	28	28	28	151	151	157	163	171	179	184	190
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
BESS	-	-	-	-	-	3	3	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Wind	20	20	20	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	40	40	40	40	83	170	195	293	302	302	262	266	266	268	268	268	268	272	276	276	276	276	276	276	276
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	126	126	126	126	126	-	-	-	-	-	-	-	-

Figure 2-15 "SB1020+SMR" Planning Scenario - Installed Capacity Mix

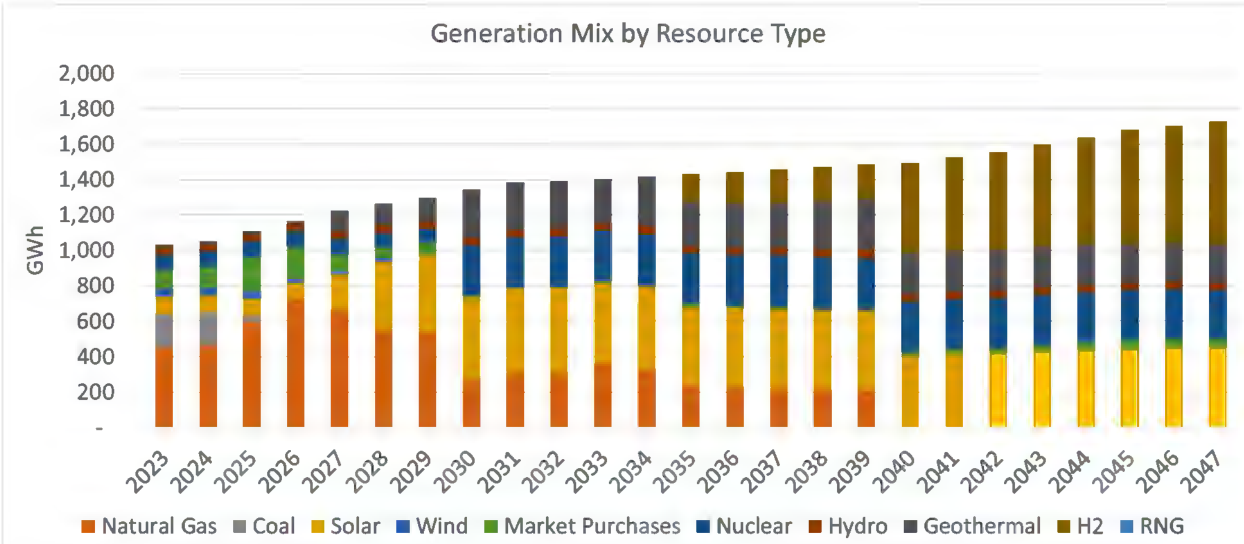


Figure 2-16 "SB1020+SMR" Planning Scenario - Generation Mix

Figure 2-17 "SB1020+SMR" Planning Scenario – RPS Percentage

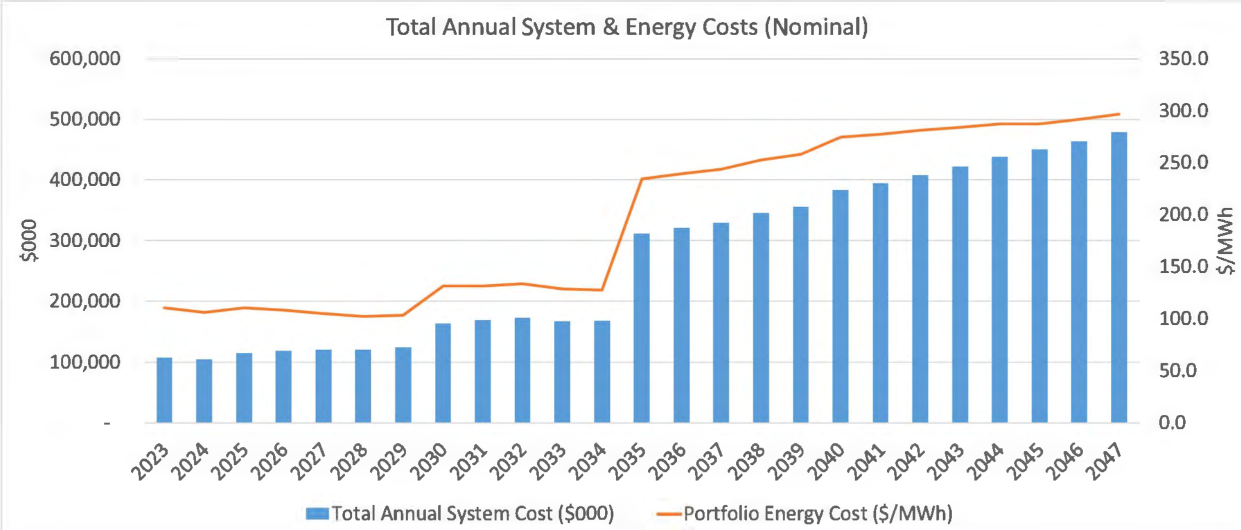


Figure 2-18 "SB1020+SMR" Planning Scenario - Total System and Energy Costs

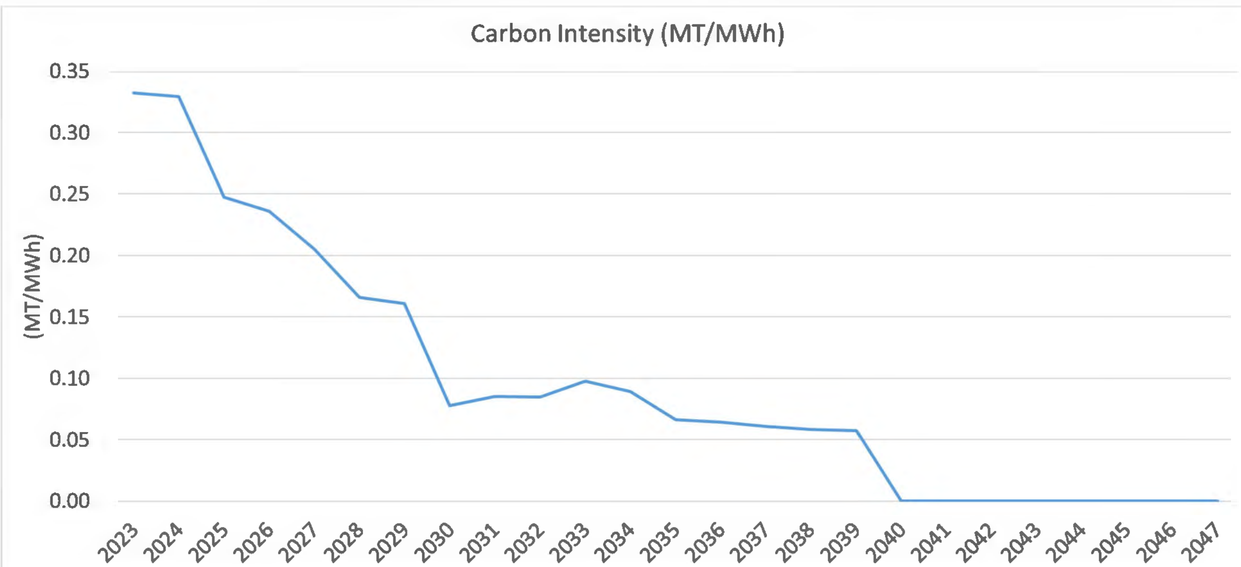


Figure 2-19 "SB1020+SMR" Planning Scenario - Carbon Intensity

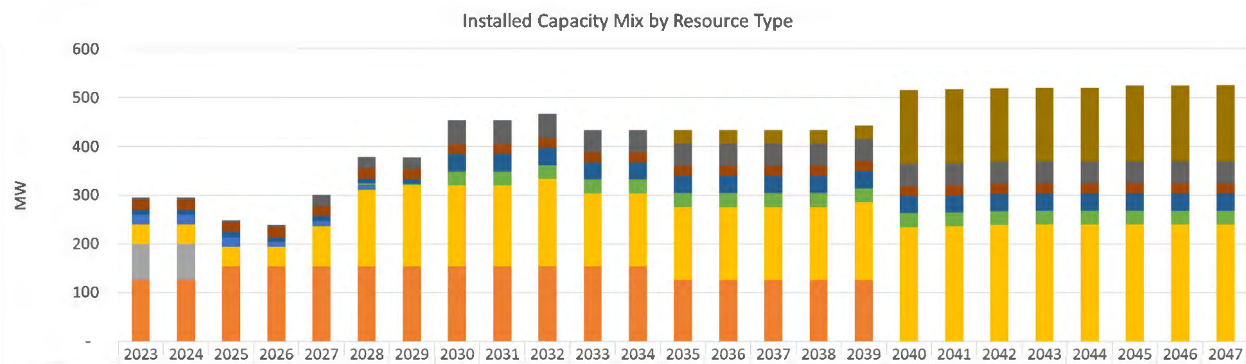
2.6.4 "SB1020 + SMR w/ 50% DEV & EV Demand" Planning Scenario

The uncertainties inherent in the forecast of long-term trends in the demand for electricity made it prudent to include sensitivity cases focused on the effects of Burbank's demand that might be higher or lower than what was assumed in the Base Case. This sensitivity scenario includes assumptions that are largely the same as the SB1020 + SMR scenario above, but also includes a 50% reduction in the demand associated with new development projects within Burbank and a 50% reduction in the anticipated electric vehicle charging demand. The remaining components of the demand forecast remain the same as those used in the Base Case. Additional detail on how Burbank's demand was calculated is included in Section 3.5 below.

Since the additional demand from new development projects is assumed to be phased over a period of seven years starting in 2025 and the additional demand from electric vehicle charging is expected to accelerate over time, the early years of the simulation are the least affected by the change in assumptions for demand. However, as electric vehicle demand becomes an increasingly large fraction of the total Burbank load over time, the assumed 50% reduction becomes more evident and therefore has a greater impact in the latter half of the study period. Note that in the time since the modeling assumptions for this IRP were finalized, it has come to pass that more development projects have been planned for Burbank. Therefore, a 50% reduction in new development demand may not be a high probability outcome.

Buildout was lower in this scenario compared to both the Base Case & SB1020 + SMR portfolios due to the lower demand assumption. Particularly of note were reductions in solar and wind energy along with less hydrogen-fuel based generation being built late in the study period. Market purchases of energy were also found to be lower than in the Base Case. These changes in results were all in line with expectations due to the assumptions made for this scenario.

Lower demand within this scenario (approx. 13% lower than the Base Case) resulted in overall lower carbon emissions (approx. 20% lower than the Base Case) since less total energy, some of which comes from fossil-fuel resources prior to 2040, had to be generated to meet Burbank's needs. Total system cost over the study period was higher than in the Base Case, but lower than in the SB1020 + SMR planning scenario.



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RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	28	28	28	28	28	151	151	151	151	151	155	155	156
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
BESS	-	-	-	-	-	3	3	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Wind	20	20	20	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	40	40	40	40	83	158	166	166	166	179	150	150	150	150	150	150	160	235	236	239	240	240	240	240	240
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	126	126	126	126	126	-	-	-	-	-	-	-	-

Figure 2-20 "SB1020+SMR w/ 50% DEV & EV Demand" Planning Scenario - Installed Capacity Mix

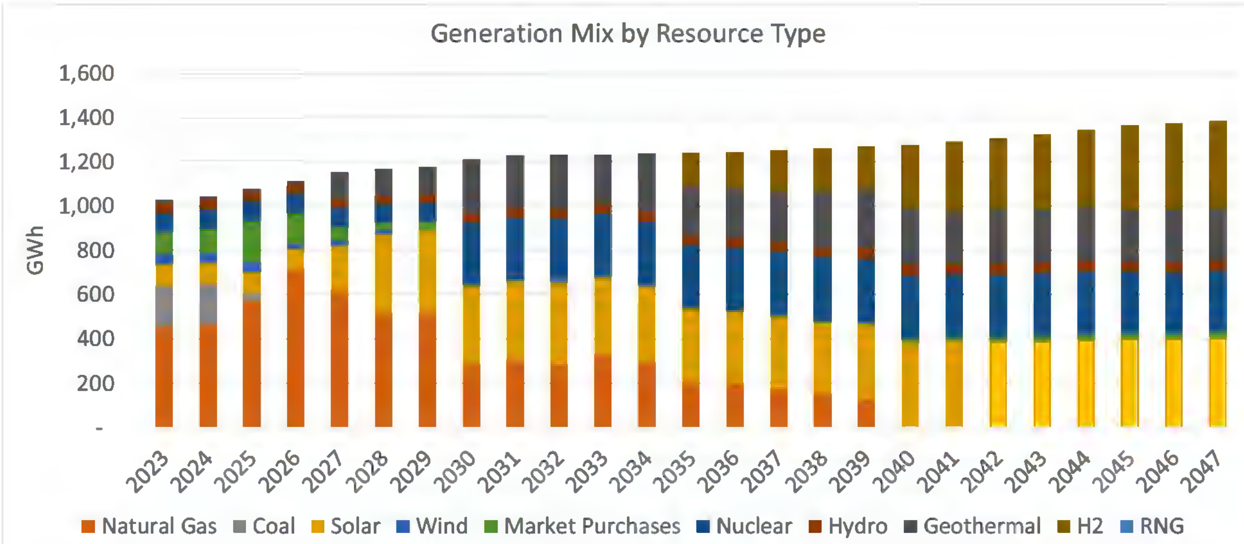


Figure 2-21 "SB1020+SMR w/ 50% DEV & EV Demand" Planning Scenario - Generation Mix

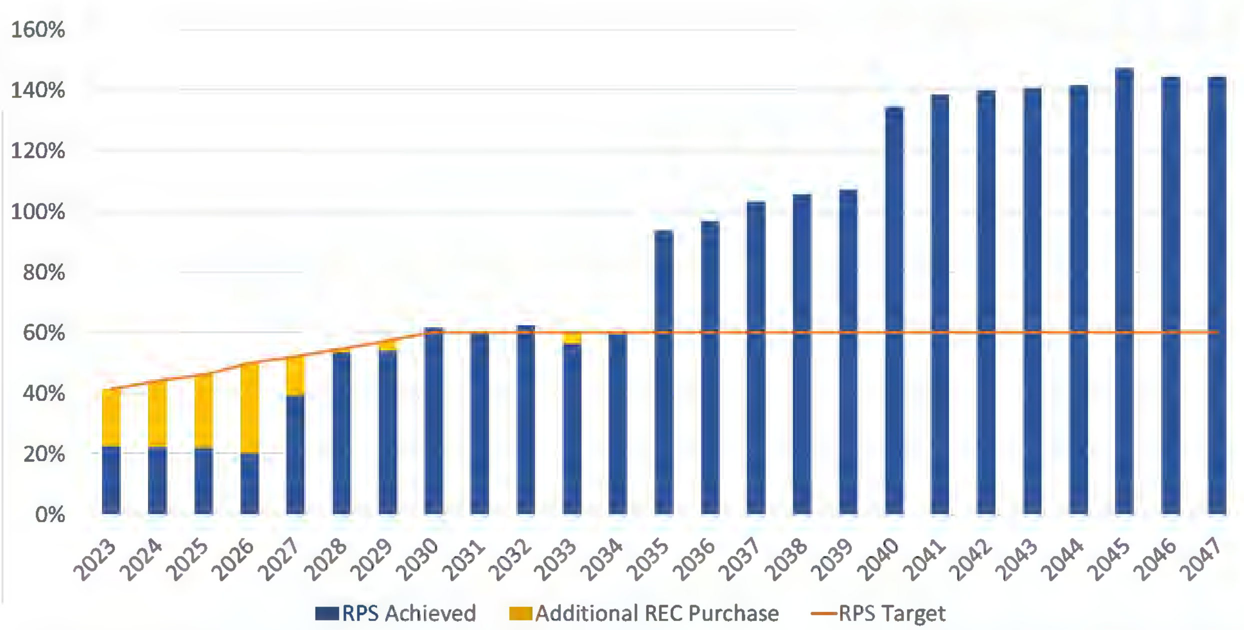


Figure 2-22 "SB1020+SMR w/ 50% DEV & EV Demand" Planning Scenario – RPS Percentage

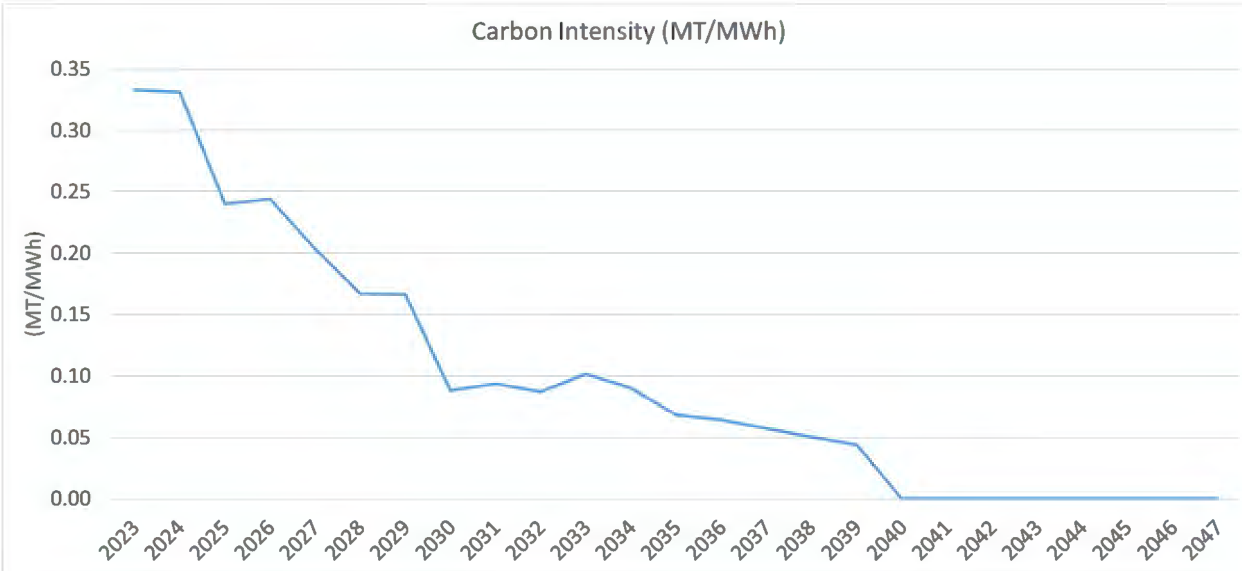


Figure 2-23 "SB1020+SMR w/ 50% DEV & EV Demand" Planning Scenario - Carbon Intensity

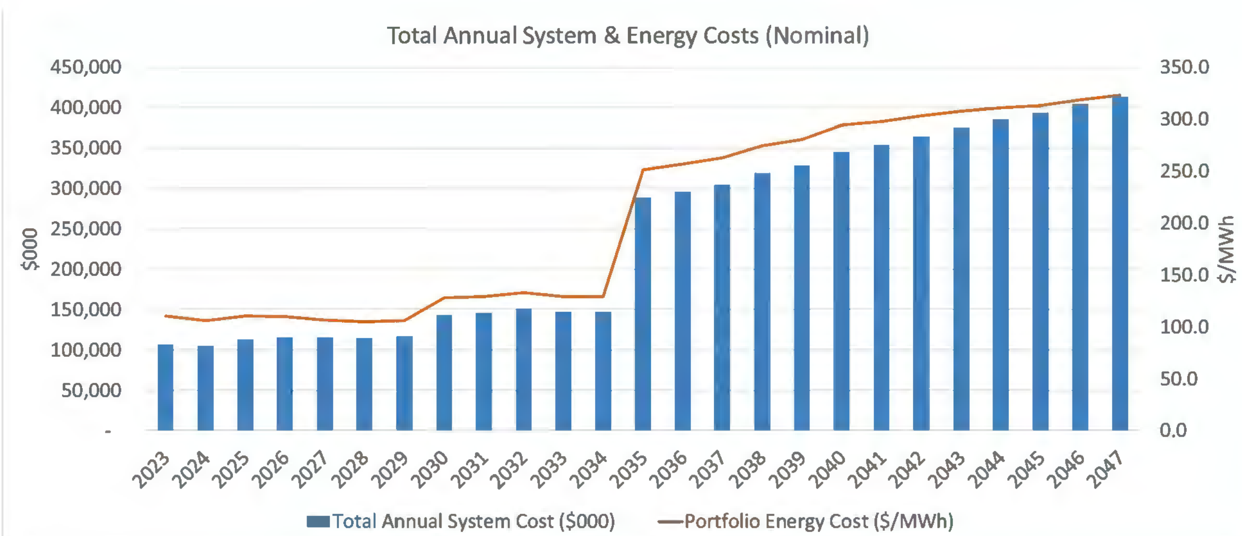


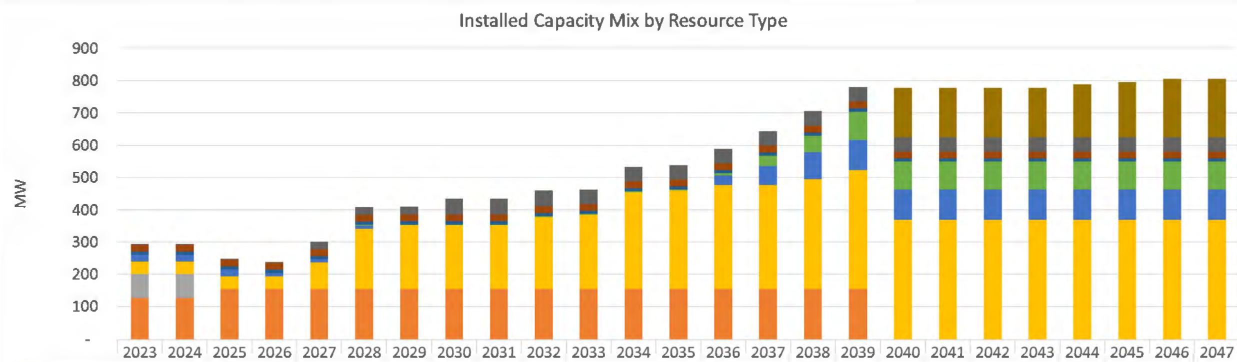
Figure 2-24 "SB1020+SMR w/ 50% DEV & EV Demand" Planning Scenario - Total System and Energy Costs

2.6.5 "10% Higher EV & DEV Demand" Planning Scenario

The uncertainties inherent in the forecast of long-term trends in the demand for electricity made it prudent to include sensitivity cases focused on the effects of Burbank's demand that might be higher or lower than what was assumed in the Base Case. Of particular interest are the contributions to future demand from planned development projects within Burbank and the demand associated with the increased adoption and charging of electric vehicles because they are the key drivers in Burbank's demand growth. Within this sensitivity scenario, the assumed demand from those two categories was increased by 10%. All other assumptions and inputs from the Base Case remained unchanged.

With the assumption that total demand will be higher in this scenario, more total energy was needed to be generated to meet Burbank's energy needs. Consequently, moderate increases in the total build-out of generating facilities were calculated within the model. Compared with the Base Case, more hydrogen-fueled combustion turbine capacity was built along with higher wind and solar capacity. Market purchase of energy were also found to be somewhat greater. All of those results were in line with expectations due to the assumptions made for this scenario.

Since electric vehicle and new development demand are only a portion of total demand, this scenario resulted in a total demand increase relative to the Base Case of 2.6% with an increase in total system cost. Likewise, a small increase of about 1% in total carbon emissions was calculated. This was expected due to the need to generate slightly more electricity from fossil-fueled resources prior to their phase out in 2040.



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151	151	151	163	170	179	180
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
BESS	-	-	-	-	-	3	3	3	3	3	3	3	3	7	32	51	87	87	87	87	87	87	87	87	87
Wind	20	20	20	10	10	10	-	-	-	-	-	-	-	28	58	84	94	94	94	94	94	94	94	94	94
Solar	40	40	40	40	83	188	198	198	198	224	231	301	306	324	324	341	369	369	369	369	369	369	369	369	369
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	-	-	-	-	-	-	-	-

Figure 2-25 "10% Higher EV & DEV Demand" Planning Scenario – Installed Capacity Mix

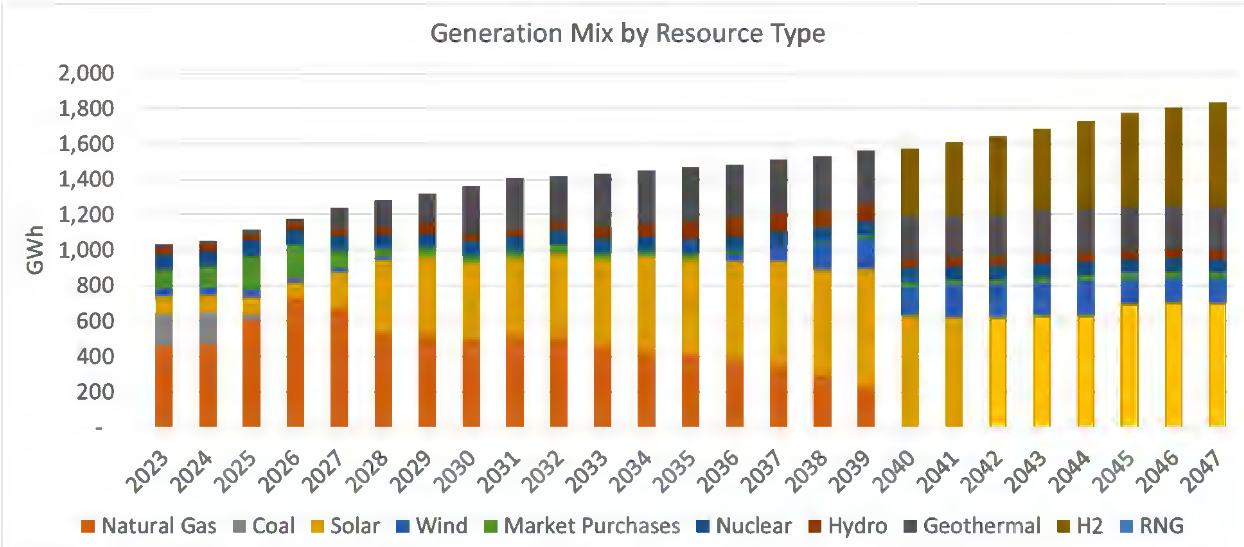


Figure 2-26 "10% Higher EV & DEV Demand" Planning Scenario – Generation Mix

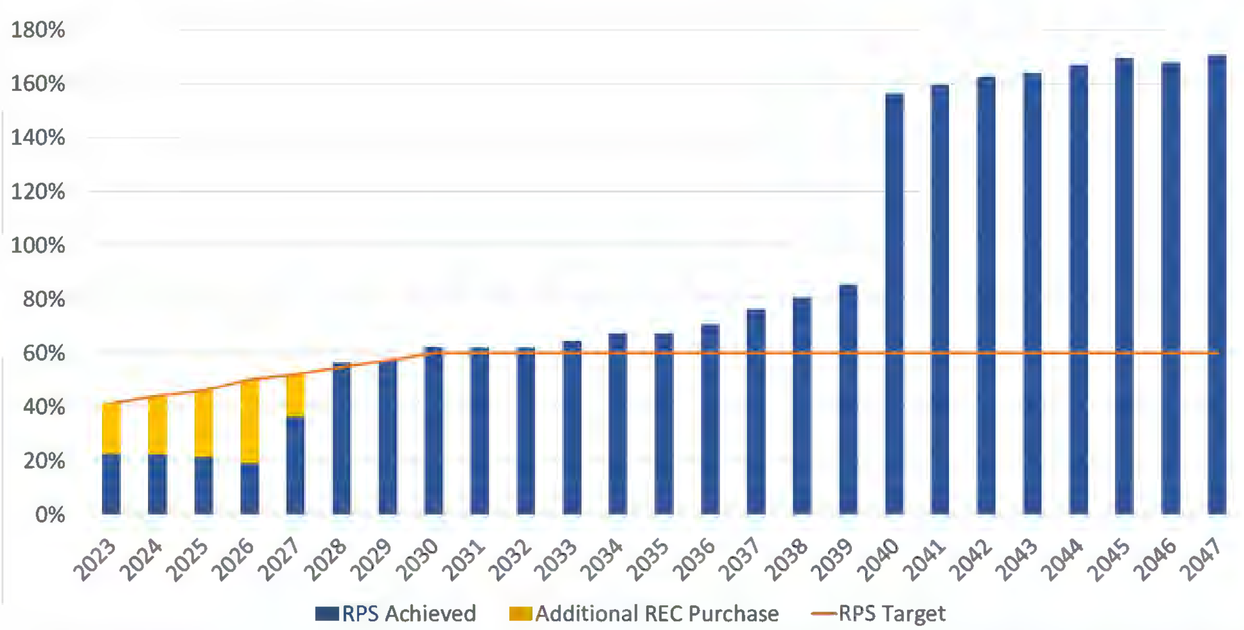


Figure 2-27 "10% Higher EV & DEV Demand" Planning Scenario – RPS Percentage

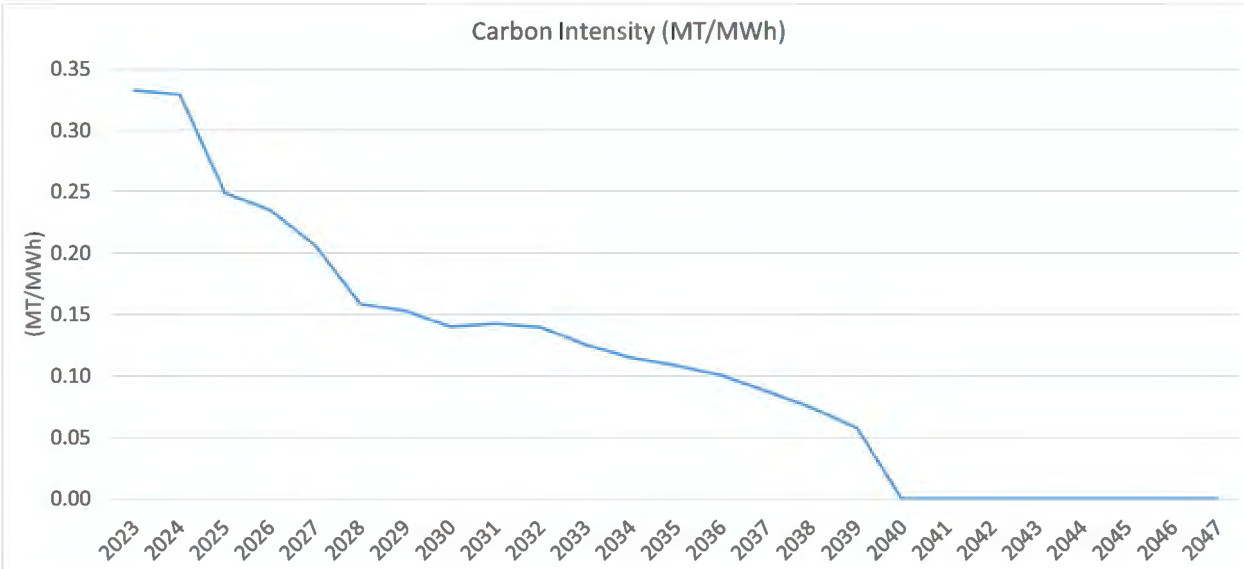


Figure 2-28 "10% Higher EV & DEV Demand" Planning Scenario – Carbon Intensity

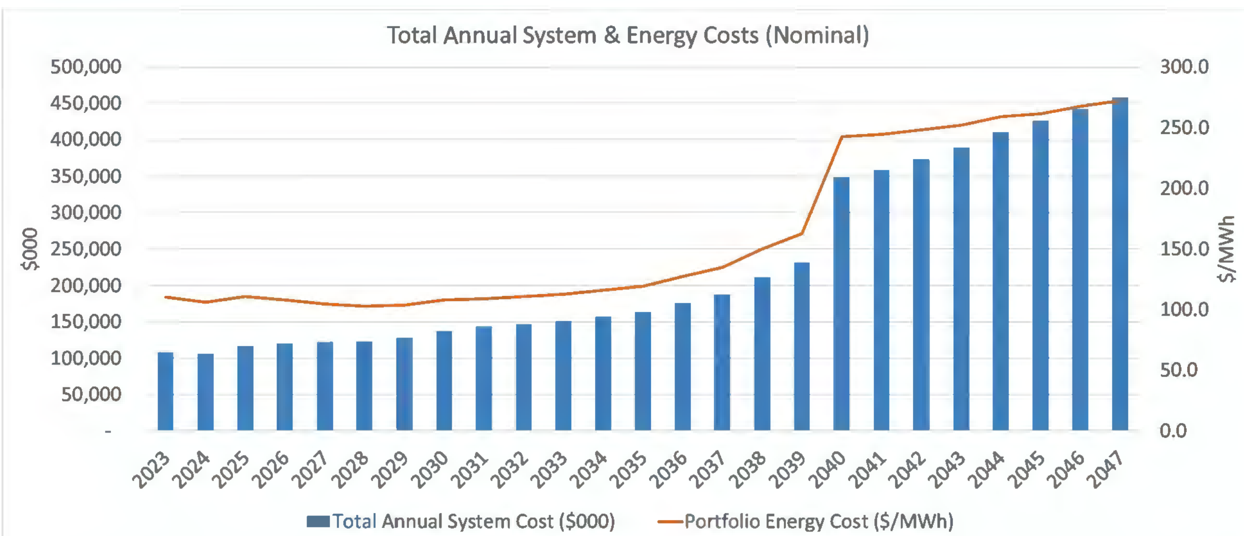


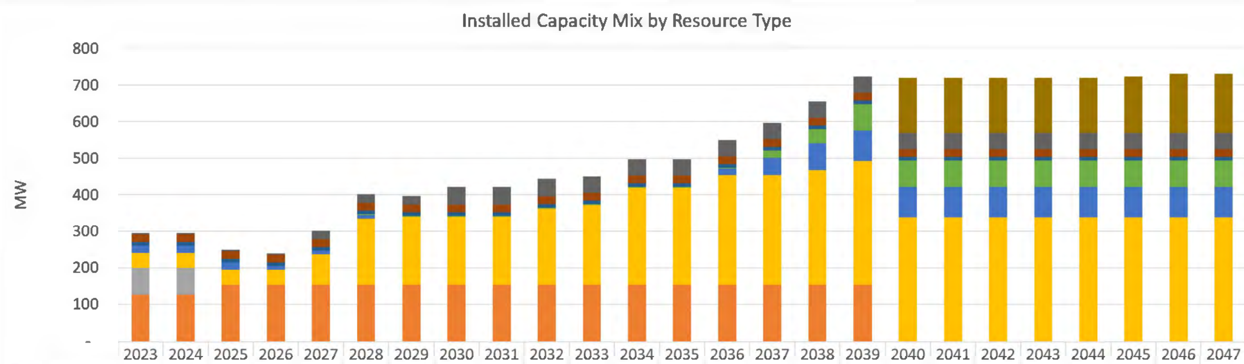
Figure 2-29 "10% Higher EV & DEV Demand" Planning Scenario – Total System and Energy Costs

2.6.6 "10% Lower EV & DEV Demand" Planning Scenario

The uncertainties inherent in the forecast of long-term trends in the demand for electricity made it prudent to include sensitivity cases focused on the effects of Burbank's demand that might be higher or lower than what was assumed in the Base Case. Of particular interest are the contributions to future demand from planned development projects within Burbank and the demand associated with the increased adoption and charging of electric vehicles because they are the key drivers in Burbank's demand growth. Within this sensitivity scenario, the assumed demand from those two categories was decreased by 10%. All other assumptions and inputs from the Base Case remained unchanged.

With the assumption that total demand will be lower in this scenario, less total energy was needed to be generated to meet Burbank's energy needs. Consequently, moderate decreases in the total build-out of generating facilities were calculated within the model. Compared with the Base Case, less hydrogen-fueled combustion turbine capacity was built along with lower wind and solar capacity. Market purchase of energy were also found to be somewhat lower. All of those results were in line with expectations due to the assumptions made for this scenario.

Since electric vehicle and new development demand are only a portion of total demand, this scenario resulted in a total demand decrease relative to the Base Case of 2.6% with a decrease in total system cost. Likewise, a small decrease of about 1% in total carbon emissions was calculated. This was expected due to the need to generate slightly less electricity from fossil-fueled resources prior to their phase out in 2040.



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151	151	151	151	154	161	162
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
BESS	-	-	-	-	-	3	3	3	3	3	3	3	3	3	20	37	71	71	71	71	71	71	71	71	71
Wind	20	20	20	10	10	10	-	-	-	-	-	-	-	17	47	74	84	84	84	84	84	84	84	84	84
Solar	40	40	40	40	83	181	185	185	185	208	218	265	265	300	300	313	338	338	338	338	338	338	338	338	338
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	-	-	-	-	-	-	-	-

Figure 2-30 "10% Lower EV & DEV Demand" Planning Scenario – Installed Capacity Mix

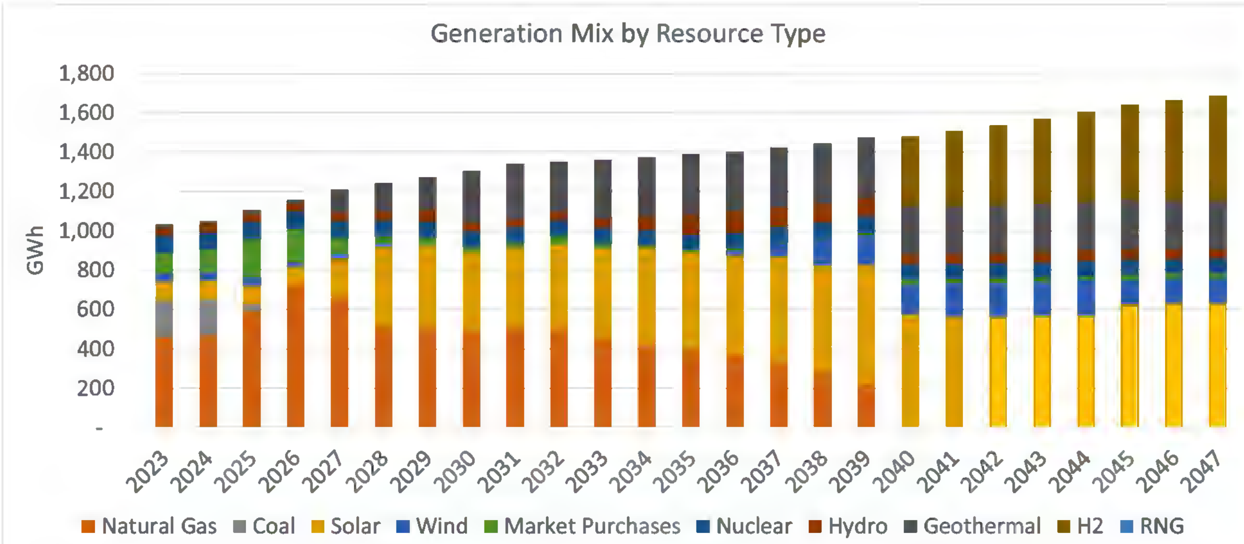


Figure 2-31 "10% Higher EV & DEV Demand" Planning Scenario – Generation Mix

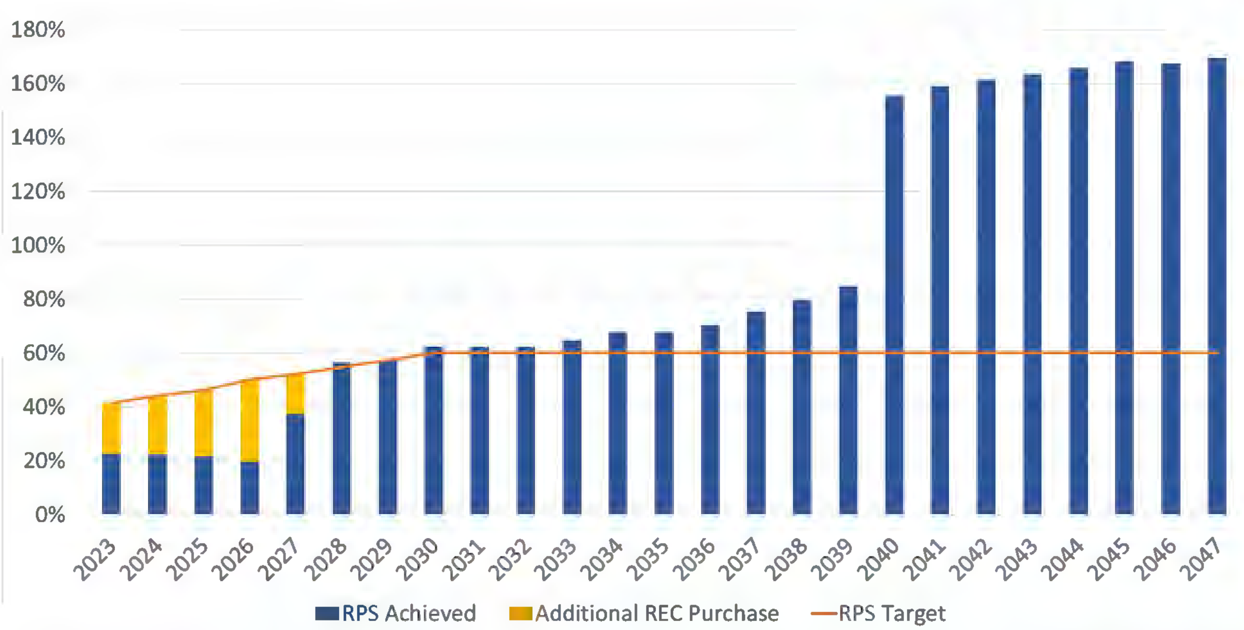


Figure 2-32 "10% Higher EV & DEV Demand" Planning Scenario – RPS Percentage

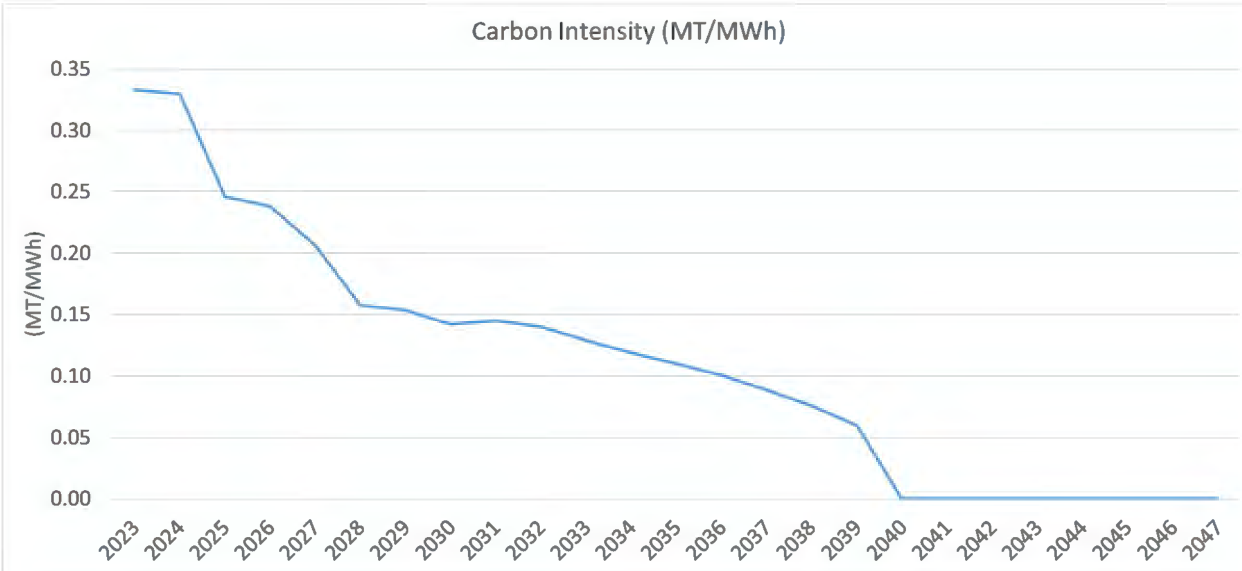


Figure 2-33 "10% Lower EV & DEV Demand" Planning Scenario – Carbon Intensity

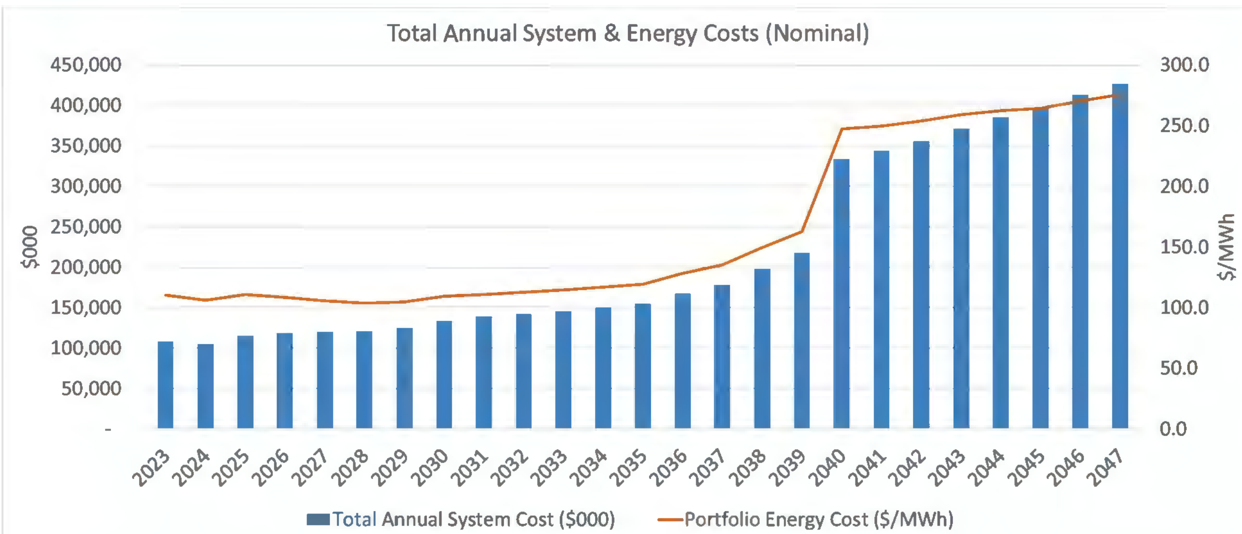


Figure 2-34 "10% Lower EV & DEV Demand" Planning Scenario – Total System and Energy Costs

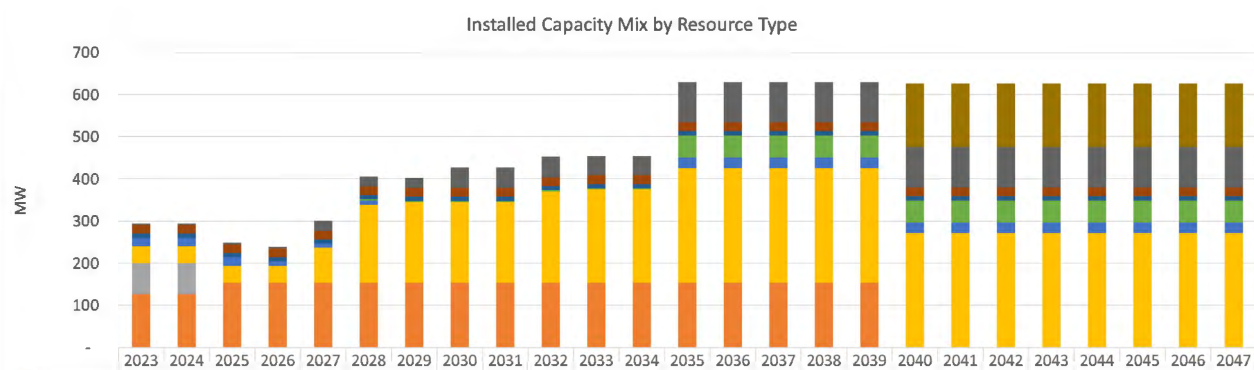
2.6.7 "New Transmission & PPAs" Planning Scenario

To achieve a carbon free future for Burbank, the obstacle of transmission investments, upgrades, and advancements will need to be addressed. Transmission upgrades can dictate where future generating resources can be located, and it is important for BWP to keep a close eye on how the transmission system advances in the case that certain upgrades could lead to beneficial resource procurement opportunities. The New Transmission & PPAs planning scenario is predicated on the addition of new transmission lines that would potentially be in-service by 2035. These new transmission lines would allow BWP to acquire power from resources it otherwise would not be able to due to transmission constraints. It is important to note that if these transmission upgrades do not materialize that this portfolio would no longer be a viable option.

The major changes from the Base Case made to create this scenario are the transmission upgrades and the new generating resources that they facilitate. The new generating resources are 50MW of solar within California, 50MW of geothermal power (also from within California), and 25MW of wind from New Mexico & Arizona. These potential resource additions are diverse and align with BWP's RPS and CES goals. Although BWP does not have to provide the new transmission capital, BWP will have to enter into Transmission Service Agreements (TSAs) for these resources. The cost associated with the TSAs have been incorporated into this analysis.

As compared to the Base Case, the major portfolio change in this planning scenario is the addition of an additional 50MW of geothermal power starting in 2035. Geothermal power plants have a higher capacity factor than intermittent solar or wind facilities. This higher capacity factor resulted in a reduced buildout of other resources such as solar, BESS, and wind.

Compared to the Base Case, the system cost is relatively equivalent until the mid-2030s when the new transmission projects are assumed to go in-service and new PPAs can be executed. The system cost is higher in the mid to late 2030s for this portfolio compared to the Base Case; however, it is better positioned for Burbank's 2040 net-zero carbon goal and system cost is lower post 2039.



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151	151	151	151	151	151	151
Geothermal	4	4	4	4	24	24	24	49	49	49	45	45	95	95	95	95	95	95	95	95	95	95	95	95	95
Hydro	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
BESS	-	-	-	-	-	3	3	3	3	3	3	3	53	53	53	53	53	53	53	53	53	53	53	53	53
Wind	20	20	20	10	10	10	-	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25
Solar	40	40	40	40	83	185	191	191	191	217	221	221	271	271	271	271	271	271	271	271	271	271	271	271	271
Coal	74	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	126	126	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	-	-	-	-	-	-	-	-

Figure 2-35 "New Transmission & PPAs" Planning Scenario – Installed Capacity Mix

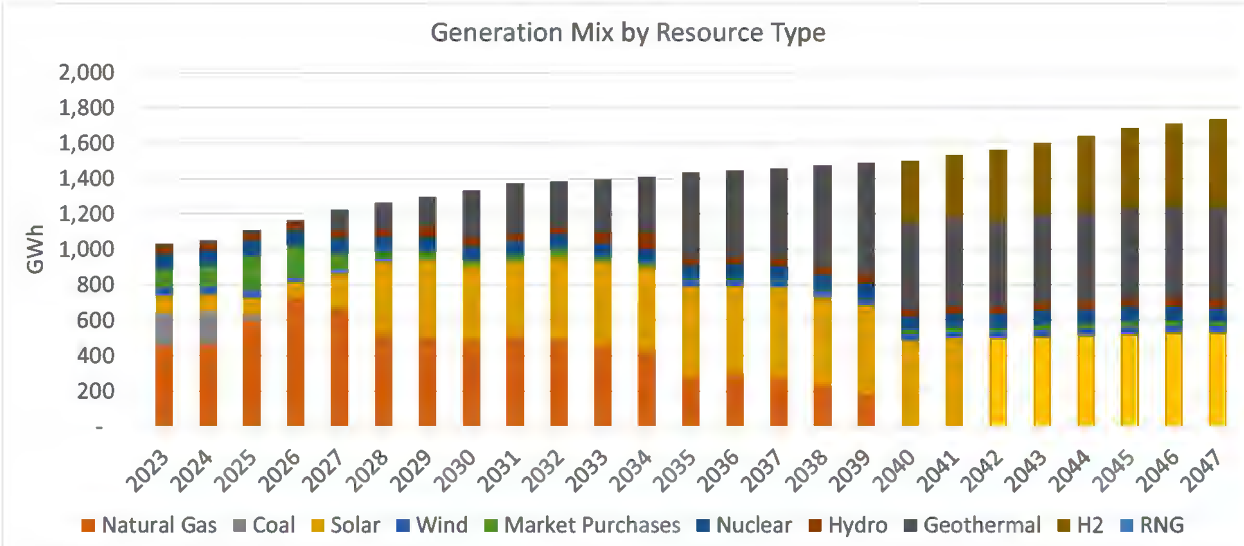


Figure 2-36 "New Transmission & PPAs" Planning Scenario – Generation Mix

Figure 2-37 "New Transmission & PPAs" Planning Scenario – RPS Percentage

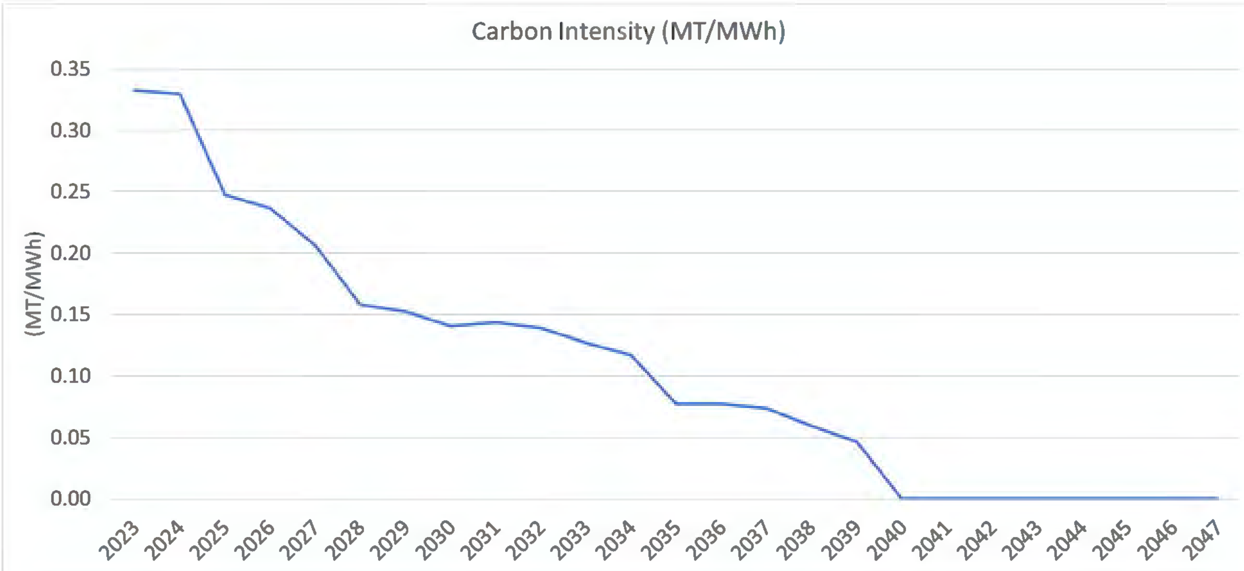


Figure 2-38 "New Transmission & PPAs" Planning Scenario – Carbon Intensity

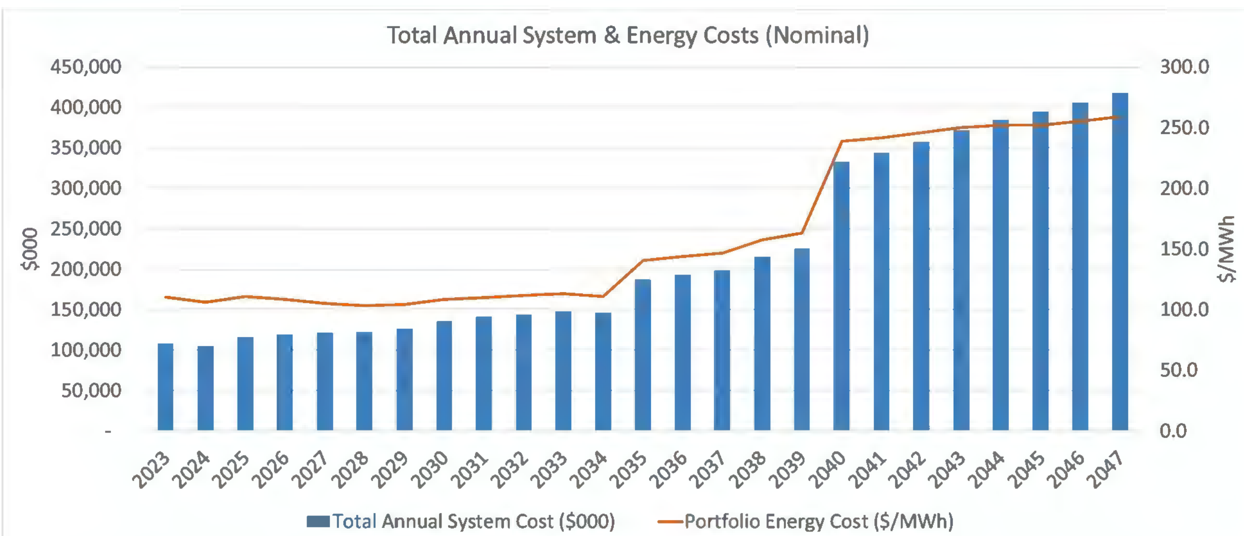


Figure 2-39 "New Transmission & PPAs" Planning Scenario – Total System and Energy Costs

2.6.8 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 IRP survey (provided as Attachment 2 to this report), indicated a preference for reliability first, followed closely by affordability and then minimizing environmental impacts. Reliability means ensuring that the lights turn on when you flip the switch and that outages are minimized. Affordability is the rate impact to BWP's customers. BWP has one of the lowest electric rates in the state. Minimizing environmental impacts means to procure renewable energy above and beyond what is required and to significantly reduce GHG emissions. The weights assigned to these characteristics along with additional details of the scorecard are listed below:

Table 2-9 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%

Table 2-10 Initial Scorecard Results

Metric	Weight	Base case	Net Zero by 2030	SB1020+SMR	SB1020+SMR w/ 50% DEV &EV Demand	10% Higher EC & DEV Demand	10% Lower EV&DEV Demand	New Transmission & PPAs
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

2.6.8.1 Recommended Scenario(s)

Given that the market conditions on which the model assumptions were based have continued to change since the initial development of the IRP, BWP removed three scenarios from consideration. Scenarios "Net Zero by 2030," "SB1020+SMR w/50% DEV & EV Demand," and "10% Lower EV &

DEV," were all removed. Through continuous monitoring of the relevant market factors, BWP determined that those three scenarios were the least likely to match Burbank's energy future.

The "Net Zero by 2030" scenario was removed because it relied solely on RNG to achieve zero carbon emissions at Magnolia and Lake One Unit. Unfortunately, as of October 2023, there are not enough RNG contracts available on the market to reach that goal. In order to plan for this scenario, BWP would need to find RNG contracts and start to negotiate for these contracts immediately.

The "SB1020+SMR w/50% DEV & EV" and "10% Lower EV & DEV" scenarios are no longer considered to be the best planning options since additional planned development projects were added to BWP's mix after the IRP assumptions were developed. As of late summer 2023, BWP has entered into negotiations with several large commercial customers which will add 30-35 MW of demand around the clock. This would add approximately 275,000 MWh of demand annually, which is a 25% increase relative to BWP's current annual energy demand. These new commercial projects were not known about at the time the assumptions and scenarios for this IRP were developed. As a result of this added demand, any scenario that projects slower energy demand growth may no longer be an optimal choice for planning future decisions.

Below in Table 2-11 are all the scenarios that were identified by BWP as being practical. Based on the results of the scorecard, the "New Transmission & PPAs" and "SB1020+SMR" options were selected as the preferred scenarios. Both scenarios were selected, as the plan for the long-term future is based on the availability of technology and ability to secure additional transmission service agreements with the Los Angeles Department of Water and Power. Both scenarios provide a path forward to SB 100 and SB 1020 compliance as well as meeting the BWP 2040 goal of 100% zero-carbon resources.

Table 2-11 Final Scorecard Results

Metric	Weight	Base case	[redacted]	SB1020+SMR	[redacted]	10% Higher EC & DEV Demand	[redacted]	New Transmission & PPAs
MODEL FOR EACH SCENARIO		PLEXOS	[redacted]	PLEXOS	[redacted]	PLEXOS	[redacted]	PLEXOS
Cost/Ratepayer Impacts	40%	39%	[redacted]	35%	[redacted]	39%	[redacted]	39%
Reliability	40%	24%	[redacted]	27%	[redacted]	21%	[redacted]	24%
Environmental Stewardship	10%	0%	[redacted]	3%	[redacted]	0%	[redacted]	1%
Diversity	10%	0%	[redacted]	8%	[redacted]	0%	[redacted]	10%
Total	100%	63%	[redacted]	72%	[redacted]	60%	[redacted]	75%
Rank		5	[redacted]	3	[redacted]	6	[redacted]	2

2.7 OTHER PLANNING CONSIDERATIONS

2.7.1 Resources

2.7.1.1 Renewable and Storage Options

The PLEXOS model used for the planning scenarios included several types of new renewable generation resources as possible future expansion options for BWP. These were wind turbines, stand-alone solar, and hybrid solar plus energy storage. Stand-alone storage was also included as an option as well.

The contributions from customer-owned distributed generation and energy efficiency were included as a part of the demand forecast and not as separately modeled generation resources.

2.7.1.2 Non-Fossil Fuel Dispatchable Technologies

Modeling provisions were also made for the construction of new hydrogen-fueled combined cycle and combustion turbines along with the conversion of existing natural gas-fired power plants to use hydrogen or RNG.

2.7.1.3 Fossil Fuel Technologies

Burbank does not plan for any new fossil fuel power generation to be added to its portfolio in the future and the construction of new natural gas- or coal-fired resources were not a part of any of the scenarios that were studied. Existing fossil-fuel power plants were assumed to continue to be used in the near-term until they are retired either due to reaching their natural end-of-life or due to the requirements to meet RPS or clean energy targets. Within the model, fossil fuel generators were also converted to use other less carbon-intensive fuels such as renewable natural gas or hydrogen.

2.7.1.4 Energy Purchases

The PLEXOS model included the ability for the BWP system to make purchases in the energy market for times when it would be the least cost option for meeting BWP's demand needs. These purchases from the spot energy market are not tied to any generating resource owned by BWP or to any long-term purchased power contract that it has entered into. Spot energy market prices are not fixed and are largely outside of the control of BWP and can therefore represent a potential risk if spot market purchases form too large of a portion of BWP's energy supply.

2.7.1.5 Reserve Obligations

In 2015, following negotiations involving technical, operational, commercial, legal, and regulatory issues, LADWP, BWP, and Glendale Water and Power (GWP) were successful in negotiating a Balancing Authority Area Services Agreement (BAASA) that is cost-based and founded on modern industry policy and practice. It is comprehensive, flexible, fair, and provides a durable basis for BWP's operations and planning.

As a part of the BAASA, BWP also negotiated the opportunity to purchase all of its reserve obligations from LADWP instead of using BWP's own assets and limited market access to provide for the reserves. BWP reserve obligations were determined during and through negotiation of the BAASA as 40 MW of spinning capacity and 40 MW of supplemental capacity for a total of 80 MW of reserve capacity. LADWP does not guarantee that the full 80 MW of these reserves will be available for purchase every year, subject to LADWP's load growth and resource planning. BWP staff works closely with LADWP staff to manage this risk.

With BWP's reserve obligations being met through LADWP, no additional reserve margin was accounted for in the modeled planning scenarios within this IRP.

2.7.2 Environmental Costs

As a city, Burbank is pursuing an aspiration goal of becoming 100% zero-carbon by 2040. That goal exceeds the California state target for 100% clean energy by 2045. Meeting mandated GHG and RPS targets unavoidably incurs costs. The costs of new energy contracts and resources that are compliant with those targets are built into all of the scenarios that were modeled for this IRP. BWP is committed to meeting its environmental mandates and goals while maintaining system reliability and affordable rates for its customers.

3 IRP Filing Contents Per CEC

3.1 PLANNING PERIOD (HORIZON)

3.1.1 Study Period

The Burbank 2024 IRP evaluates the period from 2023-2047. This study period exceeds the minimum requirements of PUC Section 9621 and allows for additional insights to be gathered as they relate to long-term planning and decision making that could impact BWP and its customers.

3.1.2 RPS Obligations

All the planning scenarios considered in this IRP include the RPS mandates from SB100 requiring an RPS of 60% by 2030. Table 3-1 details the Annual RPS Targets BWP plans to meet using a mixture of existing resources/contracts, additional procurement of renewable assets, and REC purchases. These annual RPS targets were used as a constraint in the PLEXOS model.

Table 3-1 Annual RPS Targets

Target Quantities of Renewable Energy Resources (%)									
Compliance Period 4				Compliance Period 5			Compliance Period 6		
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030+
36%	39%	41%	44%	46%	50%	52%	55%	57%	60%

Consistent with regulations, BWP is not required to demonstrate a specific quantity of procurement in any of the intervening years between 2021 up to and including 2030, however, BWP must demonstrate procurement equal to the compliance period target. BWP will submit its annual and compliance period compliance reports, as required under the California Energy Commission (CEC). Compliance periods beyond compliance period 6 will consist of three years. Each compliance period beyond compliance period 6 will need to meet an average of 60% RPS or greater of its retail sales as required by law.

3.1.3 GHG Targets

In addition to the 100% carbon free energy by 2045 target from SB100, the planning scenarios also consider Burbank's own goal of 100% carbon free energy in 2040. This is accomplished through the assumption that existing natural gas-fired generating units will be converted to run on either renewable natural gas or hydrogen fuel no later than 2040.

In the fall of 2023, the California Air Resources Board (CARB) updated its greenhouse gas planning targets for 2030. In that update, the target planning range for Burbank changed from 129,000 – 228,000 metric tonnes of carbon dioxide equivalent ($MTCO_2e$) to 129,000 – 163,000 $MTCO_2e$. This change in CARB planning targets was finalized after the modeling for this IRP was completed. All planning scenarios in this IRP result in large reductions of carbon emissions, and all achieve a net zero carbon result by 2040. However, while all the planning scenarios satisfy the previous CARB targets by 2030, only three of the planning scenarios (Net Zero by 2030, SB1020+SMR, and SB1020+SMR w/ 50% EV & DEV) achieve greenhouse gas emission reductions in line with the new CARB planning targets.

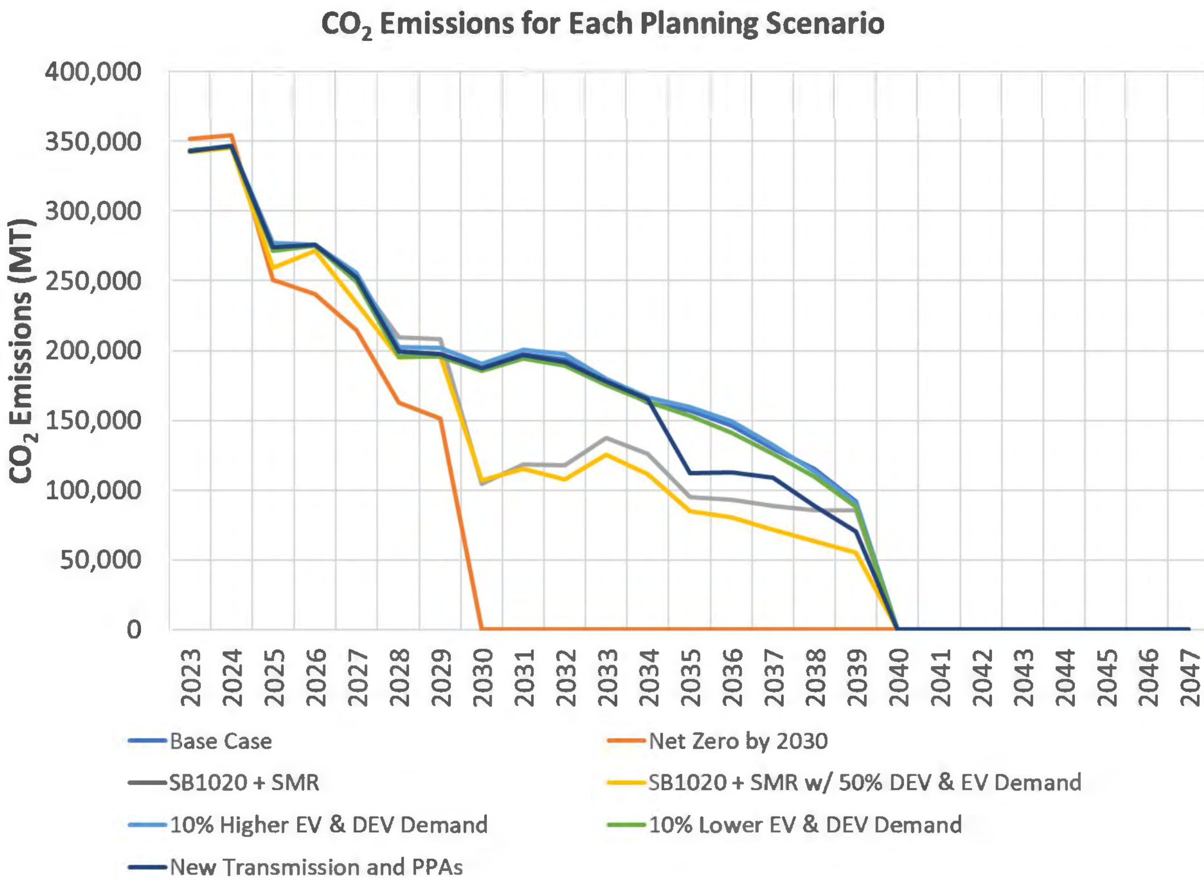


Figure 3-1 Planning Scenario Carbon Emissions

3.2 SCENARIOS AND SENSITIVITY ANALYSIS

3.2.1 Production Cost Modeling Software

The PLEXOS models evaluated resource combinations that Burbank could use to meet future requirements in the 2023-2047 planning period. PLEXOS is an industry standard capacity expansion and production cost model that is used all around the world by many different utilities and energy sector professionals. PLEXOS was used to create least cost portfolios for each of the seven planning scenarios discussed in Section 2.6. Results were calculated while obeying the operational constraints defined for the power plants and transmission components, maintaining system reliability, and serving the forecasted demand.

3.2.2 Key Inputs and Assumptions

As a long-term planning, document, the IRP is based on significant assumptions about the future. This carries inherent uncertainty, especially with the utility industry undergoing dramatic change. This IRP must make assumptions about a variety of key aspects of BWP's business during the planning period, from federal and state policy direction to the availability of cost-effective 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

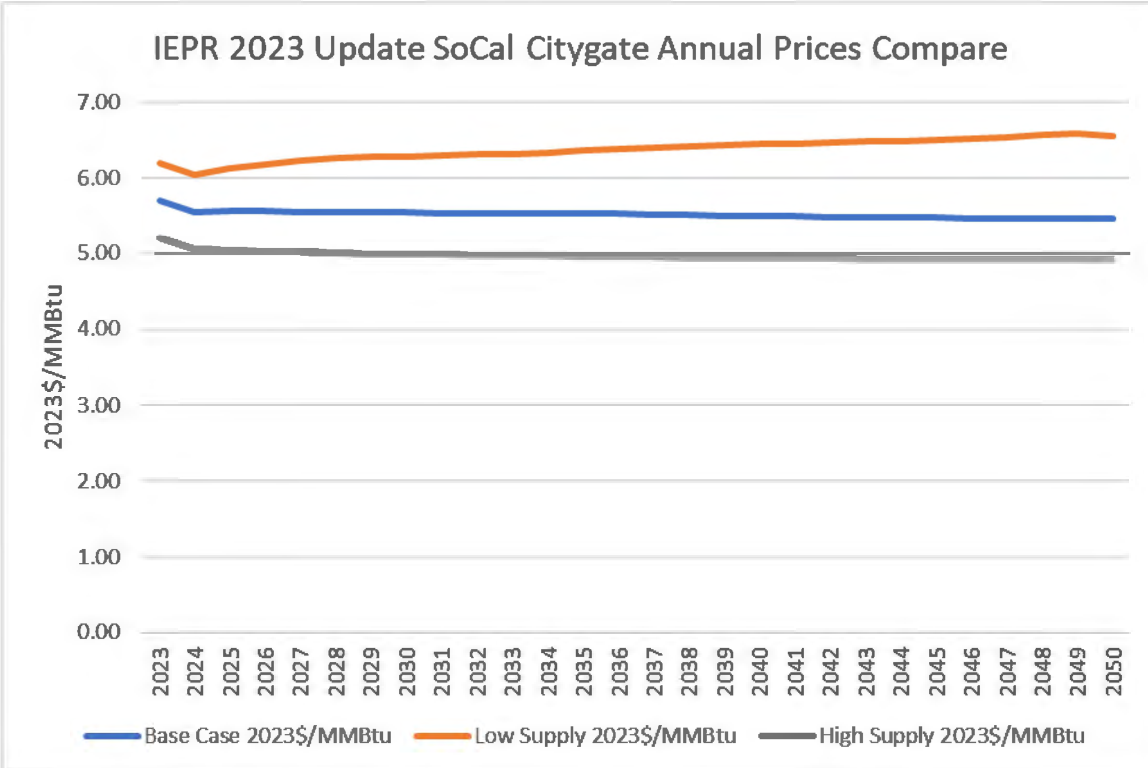


Figure 3-2 IEPR SoCal Citygate Natural Gas Price Forecast Comparison

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.

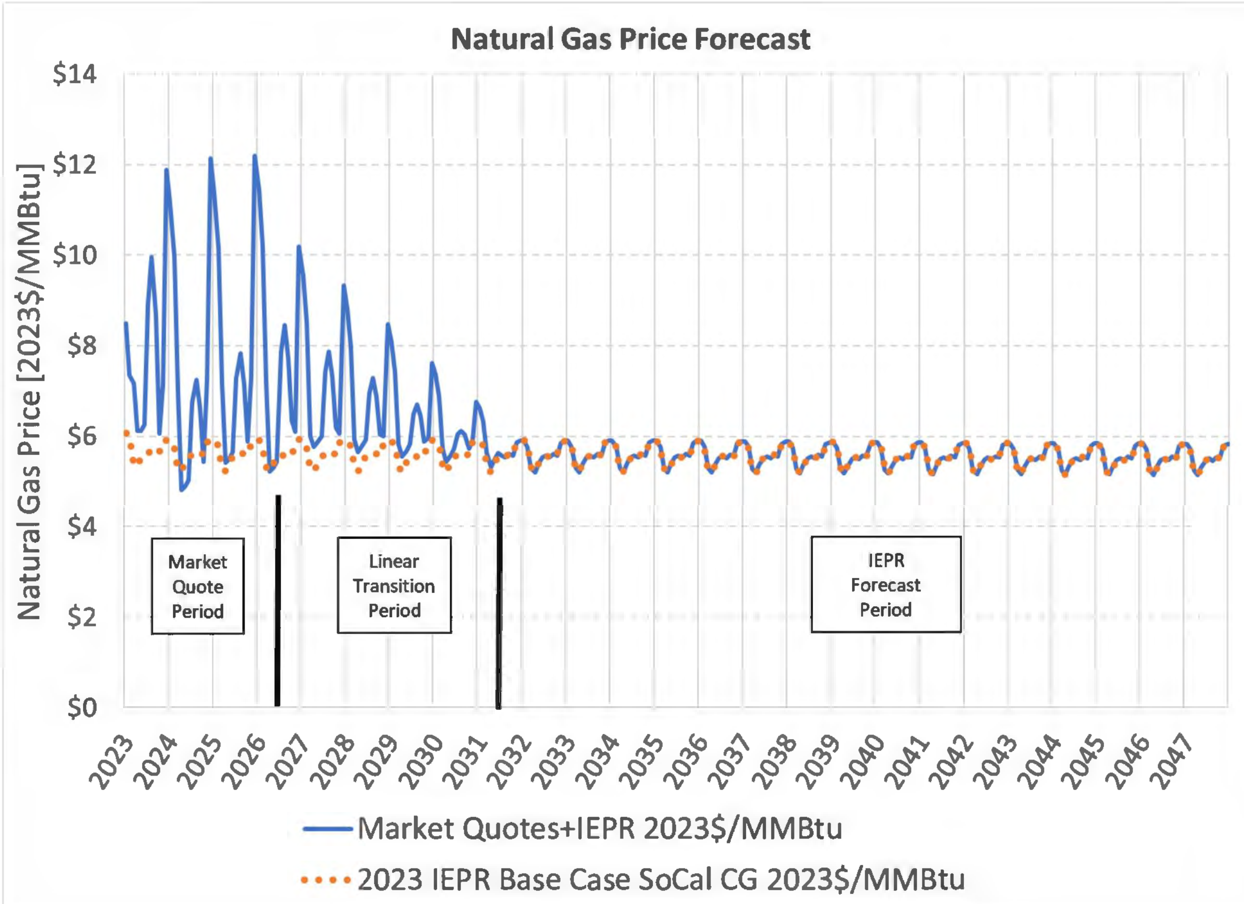


Figure 3-3 Natural Gas Price Forecast

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.

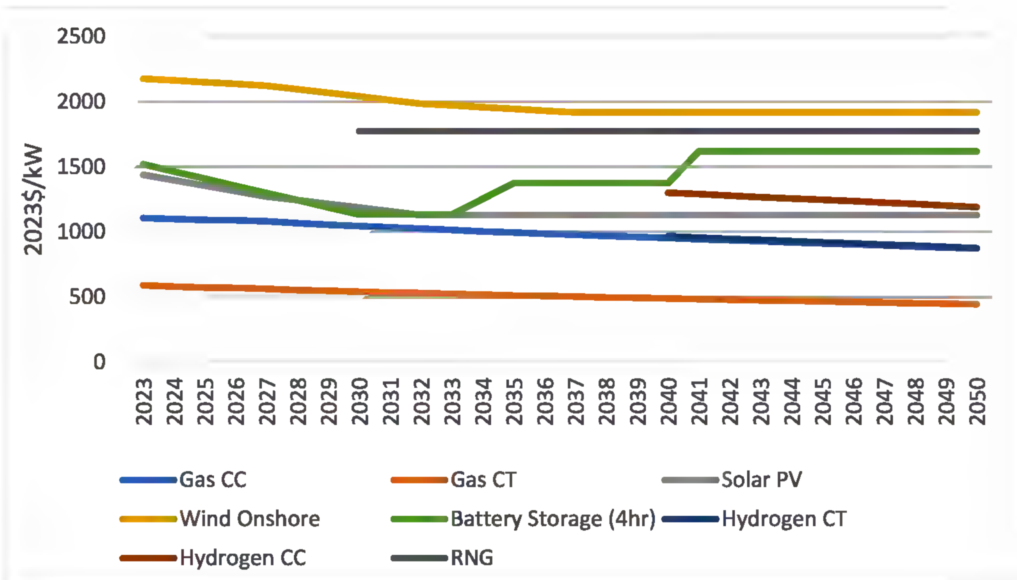


Figure 3-4 CAPEX Projections by Technology in Rockies Region

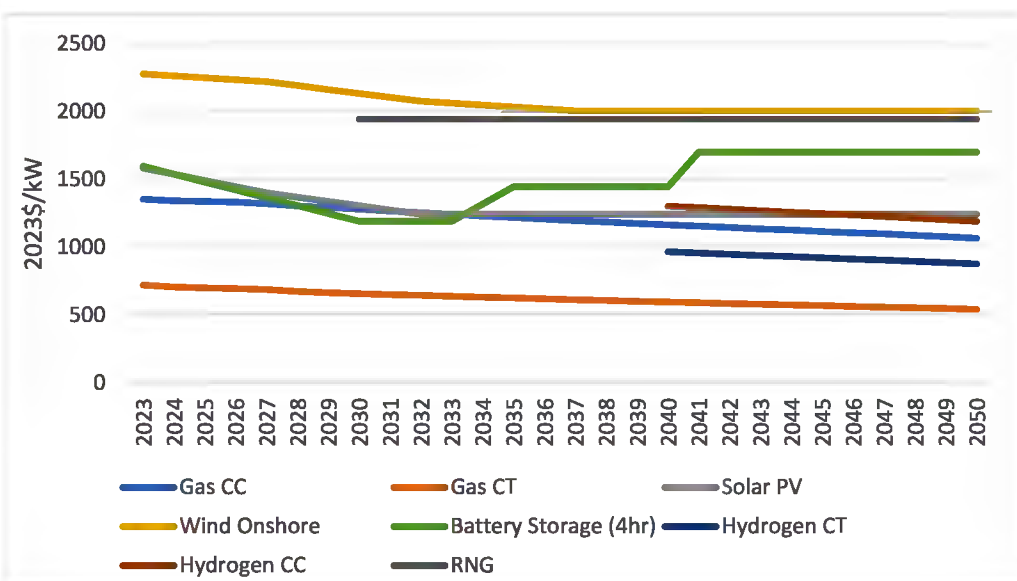


Figure 3-5 CAPEX Projections by Technology in California Region

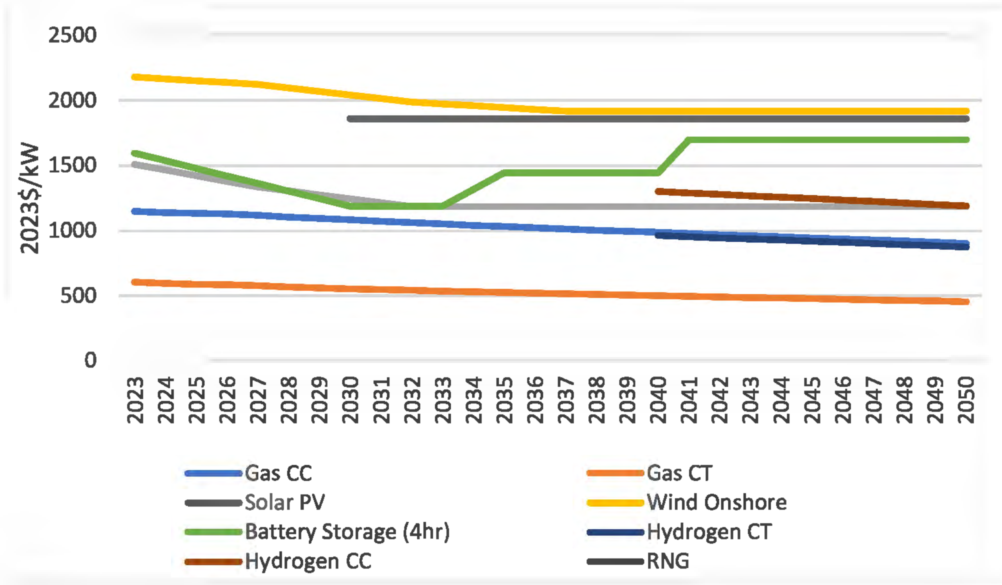


Figure 3-6 CAPEX Projections by Technology in California Neighbor Region

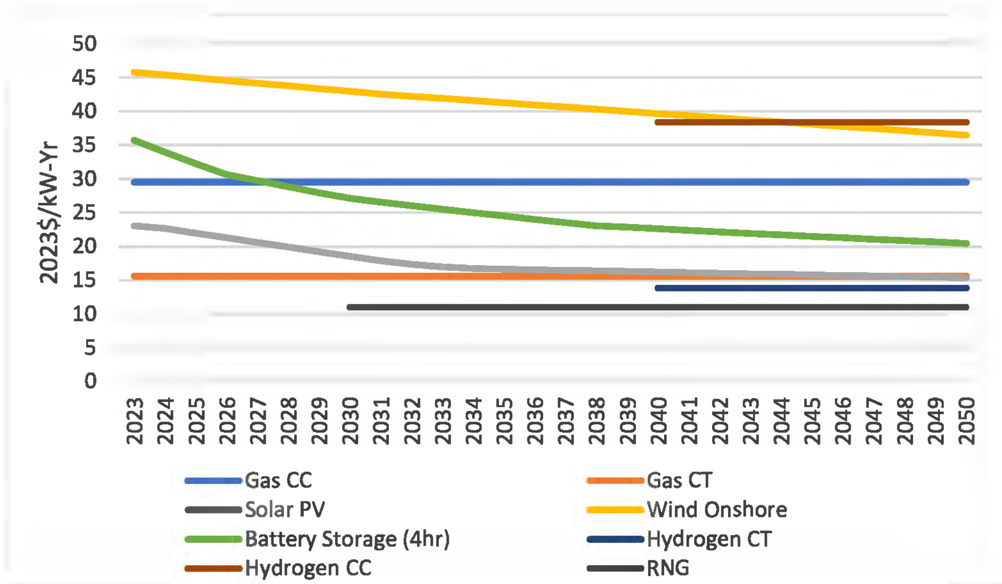


Figure 3-7 Fixed O&M Cost Projections by Technology

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.

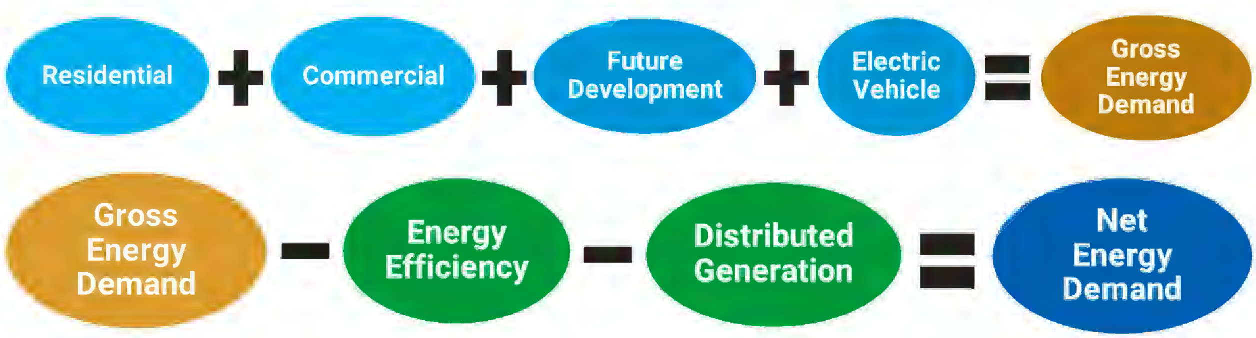


Figure 3-7 Gross and Net Energy Demand Components

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.

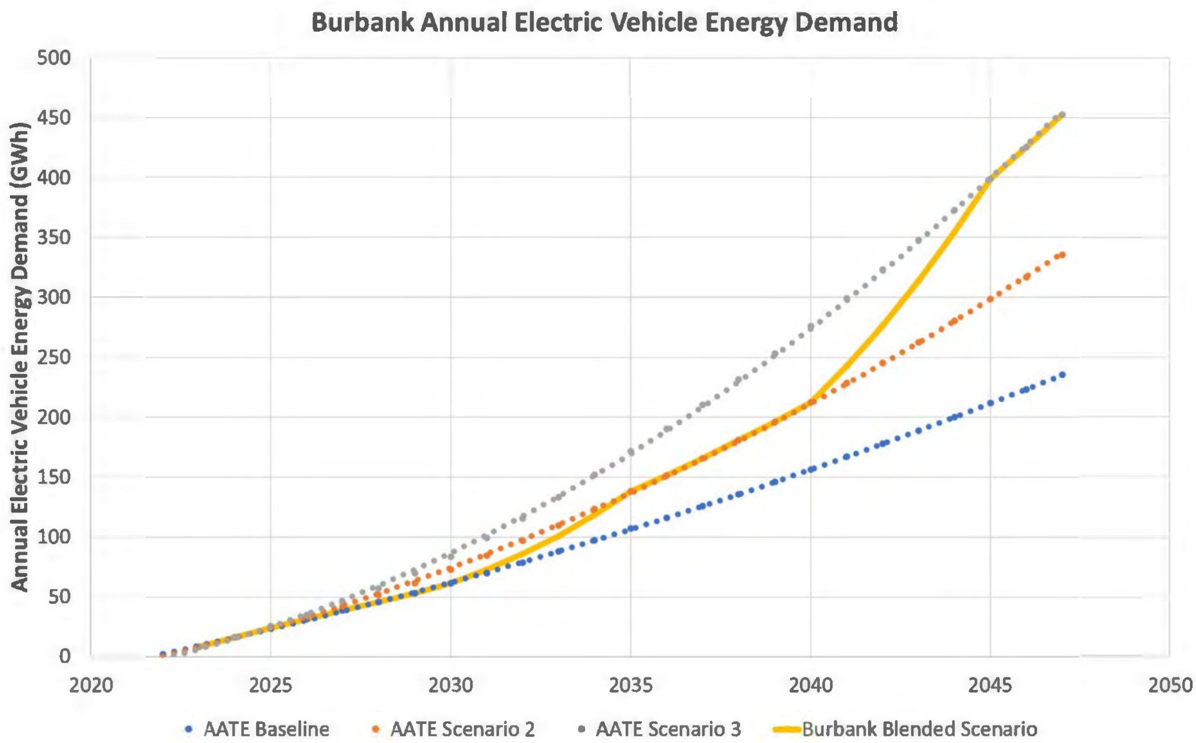


Figure 3-8 Forecast Electric Vehicle Energy Demand for Burbank

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.

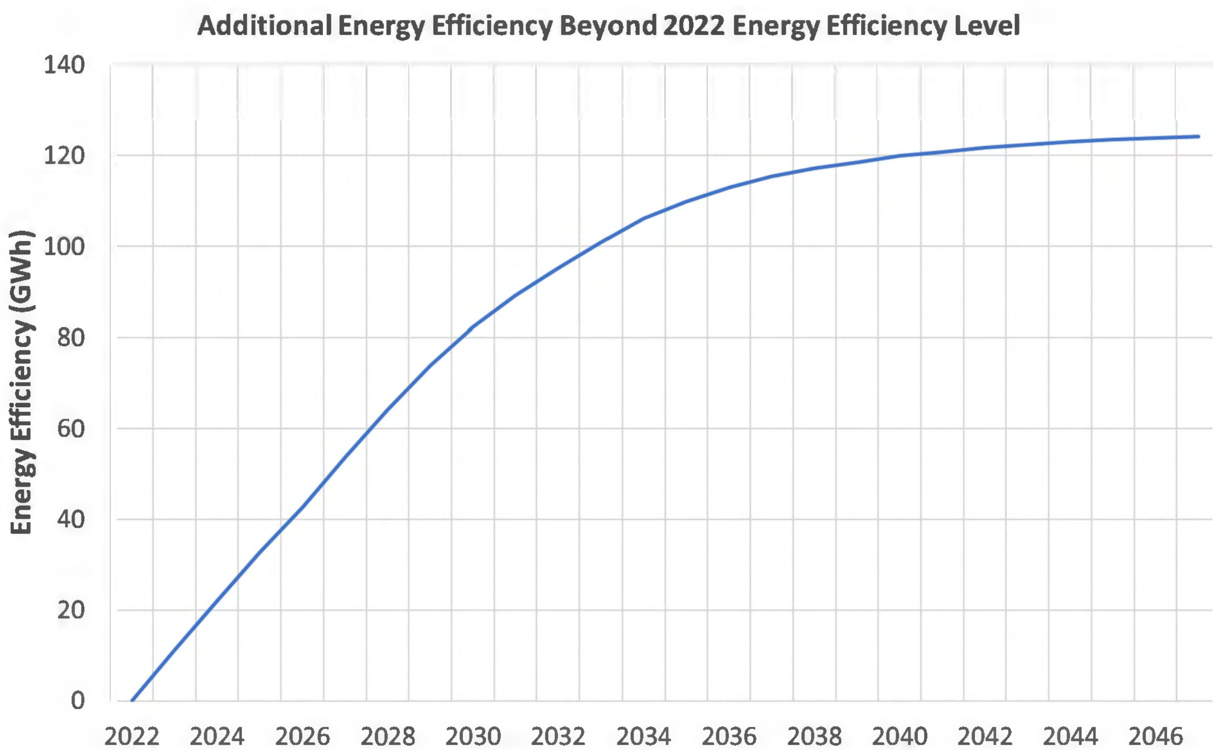


Figure 3-9 Forecasted Energy Efficiency Savings for Burbank

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.

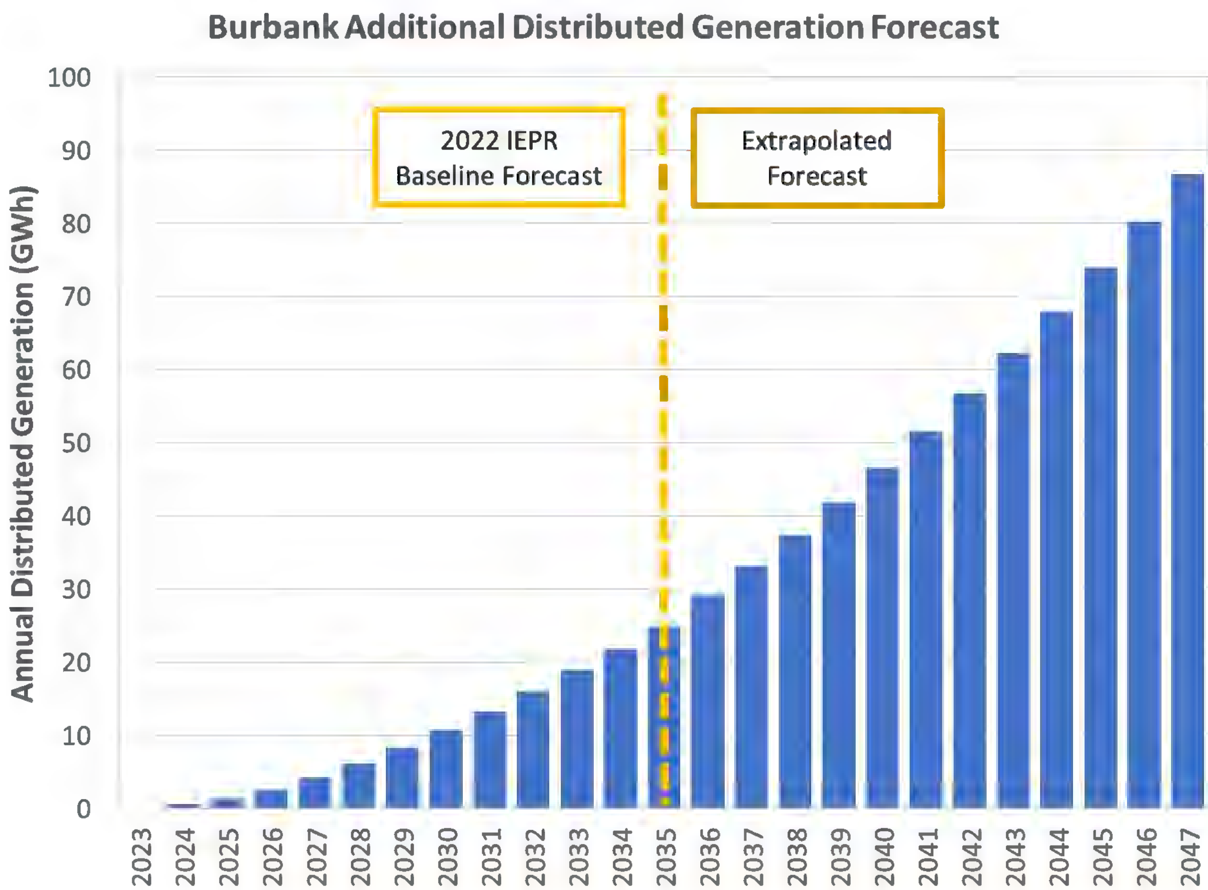


Figure 3-10 Forecasted Additional Distributed Generation for Burbank

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.