BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007

COMPLIANCE FILING OF GOLDEN STATE WATER COMPANY, ON BEHALF OF ITS BEAR VALLEY ELECTRIC SERVICE, OF ITS ALTERNATIVE PLAN

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Dated: July 31, 2018

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Pursuant to D.18-02-018[1] (the "IRP Decision"), Golden State Water Company, on behalf of its Bear Valley Electric Service ("BVES" or "Bear Valley"), respectfully submits this compliance filing of its Alternative Plan.[2]

Background of Rulemaking

This Rulemaking 16-02-007 was implemented to, among other things, adopt a two-year planning cycle for the Commission to conduct modeling and analysis, set greenhouse gas ("GHG") emission targets, and consider integrated resource plan ("IRP") filings from all load-serving entities ("LSEs"). Pursuant to Ordering Paragraph #1 of the IRP Decision, each LSE shall file either a Standard Plan or an Alternative Plan (based upon load forecasts)[3] by August 1, 2018 in this Rulemaking.[4]

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[1] D.18-02-018, Ordering Paragraph #1 at p. 170.

[2] As described herein, Bear Valley's Alternative Plan is comprised of: (i) its Integrated Resource Plan 2018-2028, plus (ii) Appendix I entitled "Alternative IRP Plan Under D.18-02-018" attached thereto.

[3] D.18-02-018, Conclusions of Law #29, at p. 168.

[4] Id. Ordering Paragraph #1 at p. 170.

History of BVES IRP

For well over a decade, Bear Valley has been preparing, updating and utilizing a robust integrated resource plan ("IRP ") to plan, evaluate and acquire energy resources to meet the forecasted energy requirements of Bear Valley's retail customers. Over this time period, Bear Valley has generally used the same format for each successive IRP, essentially updating the previous IRP to reflect changed laws, regulations, loads, forecasts and other changed circumstances from the previous IRP.

Bear Valley has previously filed an IRP with the Commission as part of its power resource procurement process. Most recently, Bear Valley filed its then-current IRP in Application 08-08-009 and later filed an updated IRP in Application 13-06-018.

The most up-to-date version of Bear Valley's IRP is the "Bear Valley Electric Service Integrated Resource Plan 2018 – 2028" ("BVES 2018 IRP").

Standard Plan Template

The Commission and its staff developed a Standard LSE Plan (also referred to as a "Standard Plan") as Attachment A to the IRP Decision. All LSEs with annual load forecasts that equal or exceed 700 gigawatt hours in California in any of the first five years of the integrated resource plan planning horizon (except PacifiCorp) shall be required to file Standard Plans utilizing the template in Attachment A of the IRP Decision.[5] As explained below, Bear Valley is not required to use the Standard Plan template.

Alternative Plan Applies to BVES

Ordering Paragraph #14 of the IRP Decision requires each LSE with an annual load forecast that is 700 gigawatt hours or less in California in any of its first five years of the integrated resource plan planning horizon (except PacifiCorp) to file an Alternative Plan.[6] Bear Valley's annual forecast load is less than 700 gigawatt hours, thereby meeting this requirement.

An Alternative Plan must consist of at least the following information (which is hereinafter referred to as the "Alternative Plan Requirements").

a) California Energy Commission (CEC) Form S1;

b) CEC Form S2 or Energy Information Administrative (EIA) Form 861 or EIA Form 861S;

[5] D.18-02-018, Ordering Paragraph #12, at p. 173.

[6] Id. Ordering Paragraph #14, at pp. 173-174.

c) CEC Power Content Report;

d) A description of the treatment of disadvantaged communities, as required in Ordering Paragraph 6 [of the IRP Decision];

e) A description of how planned future procurement is consistent with Greenhouse Gas Planning Price or its individual Greenhouse Gas Benchmark;

f) A Conforming Portfolio consistent with the Reference System Portfolio;

g) A description of any alternative or preferred portfolios along with identification and justification for any deviations in assumptions from the Reference System Portfolio;

h) A description of how the LSE's preferred portfolio is consistent with each relevant statutory and administrative requirement;

i) An action plan that includes all of the actions the LSE proposes to take in the next one to three years to implement its plan; and

j) A description of any barriers and lessons learned from the prior IRP and/or procurement cycle."[7]

The Alternative Plan Requirements are the minimum requirements a small LSE is required to submit under the IRP Decision.

BVES 2018 IRP Includes Alternative Plan Requirements.

Bear Valley added Appendix I: Alternative IRP Plan Under D.18-02-018 to its BVES 2018 IRP in order to satisfy the minimum requirements of an Alternative Plan required by the IRP Decision. Including the Alternative Plan Requirements as an appendix to Bear Valley's standard IRP format allowed Bear Valley to satisfy its minimum Alternative Plan Requirements without rewriting or reformatting its current IRP. To reformat and rewrite Bear Valley's IRP to follow the format of the Standard Plan template (Attachment A to the IRP Decision) would be a very substantial burden on Bear Valley's three-person energy department staff. It might also require the assistance (and additional cost on Bear Valley's small customer base) of outside consultants to allow Bear Valley's small energy department staff to do its other required work. Bear Valley sees no benefit to reformatting and rewriting its IRP to match the format of the Standard Plan template.

By filing its BVES 2018 IRP (which includes the required Alternative Plan Requirements in Appendix I thereto) as its Alternative Plan, Bear Valley provides over 100 pages of power resource planning information to the Commission and interested parties that exceed the minimum Alternative Plan Requirements under the IRP Decision.

[7] D.18-02-018 Ordering Paragraph #14 at pp. 173-174.

Compliance Filing of BVES Exceeds Requirements

In conclusion, Bear Valley files its Alternative Plan, attached hereto as Attachment A, which satisfies its obligations in Ordering Paragraphs #1 and #14 of the IRP Decision.

Respectfully submitted July 31, 2018, at Cerritos, California.

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ATTACHMENT A

BEAR VALLEY ELECTRIC SERVICE

INTEGRATED RESOURCE PLAN 2018 – 2028

Bear Valley Electric Service Integrated Resource Plan 2018 – 2028

July 31 2018

Bear Valley
Electric Service
A Division of Golden State Water Company

Table of Contents

1. Executive Summary

The 2018-2028 Integrated Resource Plan (IRP) for Bear Valley Electric Service (BVES) is the primary document used in planning, evaluating and acquiring energy resources to meet the forecasted energy requirements of BVES' retail customers, consistent with goals set by the State Legislature. The goal of the IRP is to identify reliable, best-fit, least-cost energy resources to serve the needs of BVES' electric customers. The amount and type of resources in the IRP must also be consistent with California Public Utilities Commission (hereafter CPUC or Commission) regulations and California State laws governing, among other issues, resource adequacy, renewable energy and greenhouse gas emissions limits.

Pursuant to D.18-02-018 (the "IRP Decision"), Golden State Water Company, on behalf of its Bear Valley Electric Service ("BVES" or "Bear Valley"), respectfully submits this compliance filing of its Alternative Plan. As described herein, Bear Valley's Alternative Plan is comprised of: (i) its Integrated Resource Plan 2018-2028, plus (ii) Appendix I entitled "Alternative IRP Plan Under D.18-02-018" attached thereto.

Note that for the IRP, BVES' analysis used retail sales adjusted for billing lag. In other words, the analysis began with billed sales and used sample load research data to allocate the retail sales by class to each of the calendar months. The result is retail sales data that can be matched to contract and production flows, the weather, and the economy. This adjusted retail sales data is then grossed up to account for line loss to derive energy requirements for the IRP.

Due to the higher than average concentration of BVES service area employment in the real estate and the tourism industry, the higher than average concentration of population in the age 55 to 65 year old cohort, and the fact that 85% of the non-permanent resident homeowners have a primary resident address in the Los Angeles-Orange County-Long Beach metropolitan area, firm sales are tied fundamentally to economic growth in specific economic drivers of the Los Angeles-Orange county-Long Beach metropolitan area. The specific economic drivers include construction activity, tourism industry economic product, and the population age 55 to 65 in the Los Angeles-Orange County-Long Beach metropolitan area. The economy of the Los Angeles metropolitan area will continue to support growth in residential and commercial classes for Bear Valley Electric through the forecast horizon.

Average snowmaking load growth began in 2015 due to the expansion of BVES' capacity to serve Bear Mountain of 1.3 MW; this growth will further increase significantly in the winter season 2019-2020 due to the planned 13 MW expansion of capacity serving Snow Summit ski resort. The snowmaking load has varied by 40% from the average annual consumption from 2004 to 2018. This will continue as weather, snow skiing traffic, and economic conditions vary the snow making load. Also this variance in the snow making load dominates the BVES system load variance in the winter months. Adding to the growth in snow making load is the 13 MW expansion in load enabled by the replacement of the 3 MW substation serving Snow Summit with two 10 MW substations. This will allow BVES to serve the snow making load at Snow Summit and provide Snow Summit an opportunity to discontinue the generation of power at Snow Summit using Snow Summit's Diesel Generation plant. This change of supply source from Snow Summit to BVES provides significant energy cost savings for Snow Summit, reduces the average revenue requirement per KWh for all BVES customers, reduces the carbon emissions at Snow Summit area, and provides a more stable load pattern and more fully utilized capacity for BVES. This is a significant increase in sales for BVES beginning November 2019.

BVES is planning a solar generation project with an 8 MW capacity utilizing 60 acres of land owned by the water treatment center for the BVES service area, BBARWA. BVES will be providing a tariff for BBARWA as part of the compensation for the use of the BBARWA land over the life of the BVES solar project. The solar project will reduce supply cost of power for BVES customers, BBARWA, and support BVES compliance with Renewable Portfolio Standards and Green House Gas emission standards set for the state of California. The incentive rate set for BBARWA will allow BBARWA to use BVES power in place of BBARWA generated power. This should increase sales significantly beginning in 2020.

A significant unknown to future retail sales is the impact of electric vehicle charging load by BVES permanent residents and visitors to the Bear Valley service area. There are as many as 6,000,000 visitors to BVES service area each year, according to the Big Bear Lake Visitors Bureau. BVES has requested funds to support the "Make Ready Charging Station" Pilot project. The project will support all the installation costs associated with the make ready program except the charging station itself. The program can support up to 100 charging station installations. The program also includes a Time of Use Rate which incentivizes electric vehicle charging during the solar producing hours as this is a time with low energy costs and excess capacity on the BVES system. This program has also removed the demand charges for residential and small commercial establishments. The barriers that remain are capital investment in an electric vehicle, the driving distance limitations, the snow conditions, and the high elevation location of the BVES service area. For this reason, BVES will have to review the results of the Pilot project study before dedicating resources dedicated to demand growth from electric vehicle charging stations.

Electric appliance efficiency gains will significantly reduce the retail sales increases created by economic growth factors mentioned above. The efficiency gains impacts lighting, heating, ventilation, home insulation, and window insulation ratings. Lighting will provide the greatest impact on efficiency gains impacting the retails sales for BVES. Both industry standards and the BVES efficiency programs have been a catalyst to these changes. Industry standards and the higher electric retail rates at BVES relative to the national average will continue to promote customer adaption of products promoting efficiency in the homes and the commercial establishments. Commercial customers are more likely to adapt these changes due the low payback periods of the product changes. Also, the increases to the operating margins of the establishments created by efficiency changes will support faster adaption of efficiency gains by the commercial sector.

The Distributed Generation using rooftop solar technology by the BVES customers has significantly dampened retail sales and will continue to increase in magnitude over the forecast horizon. Federal tax policies, BVES retail rates, technology changes in the PV market, and the BVES rate design for Net Metering customers will drive the future installation of roof top DG solar. Also, over time the penetration of the rooftop solar into the California residential and commercial rooftop will also boost the adaption of DG rooftop solar relative to what the economics of DG determine. Battery technology and price changes will also support the growth of DG even as the utilities in California, including BVES, adapt the DG rates to provide compensation for received power from DG customers to be more reflective of avoided power costs, as opposed to the recent Net Metering rate which was more of a subsidy to the DG customers, paying prices for received power which far exceeded the avoided costs of power.

However, even with healthy to moderate growth in the Los Angeles metropolitan area 2018 through 2028, the incremental BBARWA sales, Bear Mountain sales, the transportation electrification pilot project, total retail sales will be dampened significantly by the production of solar generated power by DG growth and the increases in electric appliance and home energy efficiency. Total retail sales would be declining consistently were it not for the boosts in consumption from the incremental expansions of BBARWA and Bear Mountain retail sales.

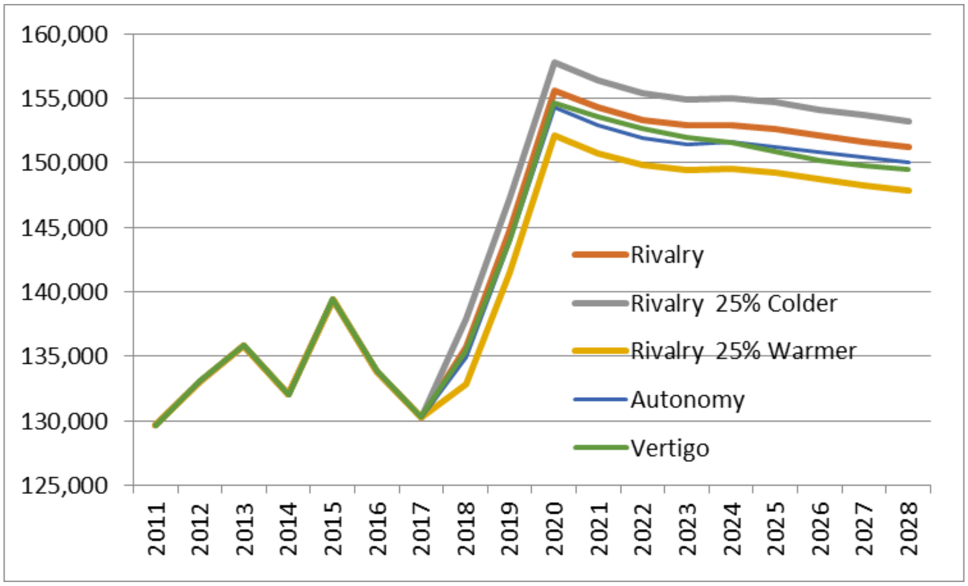
There are three categories of uncertainty in the forecast. They are as follows:

- Factors such as economic, technology adaption, environmental policy, level of trade between countries, and efficiency adaption can influence the possible outcome. Three scenarios were considered for evaluation and are labeled as Vertigo, Rivalry, and Autonomous scenarios. Rivalry is the base case, Autonomous has the most free trade and proactive environmental policies, and Vertigo is the most restrictive trade policy and has the most resistance to environmental policy implementation.
- Weather temperature ranges include 25% colder than normal temperatures, normal temperatures, and 25 % warmer than normal temperatures.
- Distributed Generation capacity growth is varied due to differences in the assumption of the solar panel costs. It is determined by the results of the economic and policy variables mentioned in bullet one.

All of these factors support the forecast for retails sales and the energy pricing environment, all of which will determine the supply portfolio for BVES and the energy supply cost for that portfolio. As the portfolio of supply and the retail sales composition changes over the 2018 to 2028 time period, so will the hourly load profile. These changes in the hourly load profile portfolio of supply will impact BVES carbon emissions across the years and the hours of the day.

The results of the forecasts are summarized below.

Figure 1: BVES Retail Sales across Scenarios in MWh



year	Rivalry	Rivalry 25% Colder	Rivalry 25% Warmer	Autonomy	Vertigo
2011	129,653	129,653	129,653	129,653	129,653
2012	133,039	133,039	133,039	133,039	133,039
2013	135,832	135,832	135,832	135,832	135,832
2014	131,993	131,993	131,993	131,993	131,993
2015	139,442	139,442	139,442	139,442	139,442
2016	133,873	133,873	133,873	133,873	133,873
2017	130,299	130,271	130,271	130,241	130,278
2018	135,730	137,900	132,825	134,932	135,344
2019	144,741	147,290	141,526	143,850	144,094
2020	155,605	157,827	152,110	154,342	154,619
2021	154,257	156,362	150,721	152,869	153,519
2022	153,317	155,383	149,805	151,898	152,670
2023	152,861	154,928	149,385	151,445	151,932
2024	152,953	155,044	149,520	151,577	151,551
2025	152,626	154,682	149,189	151,255	150,880
2026	152,108	154,142	148,699	150,800	150,208
2027	151,640	153,666	148,282	150,427	149,780
2028	151,189	153,209	147,888	150,059	149,485
2011 -2017	0.08%	0.08%	0.08%	0.08%	0.08%
2017 to 2028	1.36%	1.49%	1.16%	1.30%	1.26%

The jump in sales beginning in 2020 from Snow Summit substation expansion and from BBARWA sales does create a need to revisit the supply strategy for BVES to meet the load. BVES will be using a combination solar generation capacity of 8 MW and stored energy of 5 MW with 3 to 4 hours of storage capability, and shaped hourly load power strip firm contracts to meet the load requirements facing BVES in the forecast horizon. See table and chart below.

Table 1: BVES Supply Composition of Net Energy Requirements in MWH

Year	Energy Requirements Rivalry NW	Energy Requirements Rivalry 25% Colder Weather	Seasonal Winter Contracts	Annual Contracts	BBARWA-BVES Solar	Battery Discharge	BVPP
2011	152,027						
2012	146,236						
2013	150,133						
2014	145,768						
2015	150,388						
2016	156,258						
2017	161,565						
2018	152,018	154,985		105,120			
2019	158,931	162,318	68,600	105,120			
2020	171,776	174,791	68,600	142,954	19,769	7,300	144
2021	170,267	173,145	68,600	142,954	19,631	7,300	136
2022	169,213	172,042	68,600	142,954	19,493	7,300	128
2023	168,702	171,527	68,600	142,954	19,357	7,300	126
2024	168,806	171,652	68,600	142,954	19,221	7,300	126
2025	169,633	176,046	68,600	142,954	19,087	7,300	258
2026	169,060	175,411	68,600	142,954	18,953	7,300	257
2027	168,598	174,901	68,600	142,954	18,820	7,300	254
2028	169,111	175,369	68,600	142,954	18,689	7,300	270

The hourly composition of the BVES net energy requirements has changed significantly and will continue to shift towards a more fully utilized capacity across the higher MW levels. The significant increase in capacity utilization will begin in 2020 as the BBARWA and the supplemental Snow Summit snow making load is served by BVES. Both daytime and nighttime load will increase, filling the MW tranches from 15 MW to 50 MW. Facilitating this change in the load shape and capacity utilization will be the battery used for stored energy. Daytime load is increased as the battery charges at 5 MW capacity over a 4 hour period, and the evening to late evening load is reduced as the battery discharges. This will allow BVES to serve a load above the 47.4 MW capacity set by the SCE transmission contracted line capacity serving BVES and the BVPP capacity as well. The result is a fuller load shape that requires a higher level of firm load capacity in the contracts than required in the past. See table 2 below.

Table 2: Number of Hours where Net Energy Load is above the stated MW Levels

	Peak	Energy Req.	Load Factor	Hours BVES System Above:										Sales
Year	MW	MWh	%	5 MW	10 MW	15 MW	20 MW	25 MW	30 MW	35 MW	40 MW	45 MW	**50 MW**	KWh
2011 Actual	40.1	152,027	43.31%	8,760	8,760	5,320	1,817	1,003	376	48	1	0	**0**	133,709
2012 Actual	43.6	146,236	38.29%	8,760	8,760	5,088	1,192	594	302	69	14	0	**0**	128,616
2013 Actual	38.8	150,133	44.16%	8,760	8,757	5,340	1,591	796	418	49	0	0	**0**	132,043
2014 Actual	46.4	145,768	35.85%	8,760	8,760	5,105	1,124	565	281	95	29	4	**0**	128,204
2015 Actual	46.0	150,388	37.33%	8,760	8,755	4,799	1,564	907	539	189	46	3	**0**	132,267
2016 Actual	42.7	156,258	41.77%	8,760	8,760	6,348	1,918	764	288	57	13	0	**0**	137,430
Normal Weather														
2017	42.7	161,565	43.21%	8,760	8,760	7,051	2,189	847	300	57	13	0	**0**	142,098
2018	45.3	152,018	38.32%	8,760	8,759	5,484	1,604	783	335	140	33	1	**0**	133,701
2019	52.4	158,931	34.62%	8,760	8,760	5,587	1,857	1,086	662	344	168	55	**21**	139,781
2020	52.4	171,776	37.42%	8,760	8,760	6,111	2,430	1,758	1,137	536	289	104	**40**	151,078
2021	52.4	170,267	37.09%	8,760	8,760	5,925	2,381	1,741	1,106	521	281	99	**37**	149,751
2022	52.4	169,213	36.86%	8,760	8,760	5,804	2,354	1,729	1,088	512	274	94	**34**	148,824
2023	52.4	168,702	36.75%	8,760	8,760	5,733	2,337	1,725	1,072	504	273	92	**34**	148,375
2024	52.4	168,806	36.77%	8,760	8,760	5,747	2,339	1,726	1,070	503	271	92	**34**	148,466
2025	52.4	169,633	36.96%	8,761	8,252	5,670	2,551	1,748	1,212	607	339	195	**63**	149,194
2026	52.4	169,060	36.83%	8,760	8,409	5,435	2,511	1,745	1,211	598	341	197	**60**	148,690
2027	52.4	168,598	36.73%	8,760	8,410	5,389	2,495	1,737	1,197	595	339	195	**59**	148,283
2028	52.4	169,111	36.84%	8,781	8,427	5,396	2,511	1,752	1,200	601	338	199	**71**	148,735
25 % Colder Temperatures														
2018	47.8	154,985	37.00%	8,760	8,758	5,691	1,816	863	414	191	56	7	**0**	136,311
2019	52.4	162,318	35.36%	8,760	8,758	5,759	2,051	1,158	775	412	223	86	**28**	142,760
2020	52.4	174,791	38.08%	8,760	8,760	6,220	2,553	1,799	1285	633	339	150	**56**	153,730
2021	52.4	173,145	37.72%	8,760	8,759	6,004	2,495	1,784	1250	607	330	144	**54**	152,282
2022	52.4	172,042	37.48%	8,760	8,758	5,874	2,457	1,771	1229	596	326	137	**53**	151,312
2023	52.4	171,527	37.37%	8,760	8,758	5,812	2,445	1,768	1221	592	322	134	**52**	150,859
2024	52.4	171,652	37.39%	8,760	8,758	5,821	2,447	1,768	1222	592	322	134	**53**	150,969
2025	52.4	176,046	38.35%	8,761	8,211	5,732	2,791	1,933	1,495	846	461	282	**136**	154,834
2026	52.4	175,411	38.21%	8,760	8,355	5,520	2,767	1,905	1,492	831	467	285	**135**	154,275
2027	52.4	174,901	38.10%	8,760	8,351	5,493	2,748	1,900	1,482	820	459	281	**128**	153,827
2028	52.4	175,369	38.20%	8,781	8,368	5,485	2,758	1,912	1,484	827	460	285	**136**	154,239
25 % Warmer Temperatures														
2018	42.5	148,227	39.80%	8,760	8,759	5,121	1,378	679	277	98	9	0	**0**	130,366
2019	52.4	154,796	33.72%	8,760	8,759	5,239	1,622	995	550	293	120	40	**16**	136,144
2020	52.4	167,335	36.45%	8,760	8,760	5,772	2,253	1,676	953	434	230	72	**19**	147,172
2021	52.4	165,786	36.12%	8,760	8,760	5,592	2,199	1,661	925	418	220	67	**19**	145,810
2022	52.4	164,765	35.89%	8,760	8,759	5,444	2,161	1,649	904	409	214	65	**17**	144,912
2023	52.4	164,300	35.79%	8,760	8,759	5,389	2,150	1,644	892	404	211	65	**17**	144,503
2024	52.4	164,457	35.83%	8,760	8,759	5,405	2,153	1,645	893	406	210	65	**17**	144,641
2025	52.4	164,687	35.88%	8,761	8,229	5,450	2,389	1,644	1,020	492	268	139	**45**	144,844
2026	52.4	164,159	35.76%	8,760	8,394	5,216	2,356	1,643	1,012	487	268	141	**46**	144,379
2027	52.4	163,767	35.68%	8,760	8,394	5,183	2,346	1,640	1,001	483	266	135	**45**	144,034
2028	52.4	164,316	35.80%	8,781	8,418	5,178	2,353	1,653	1,002	487	265	139	**49**	144,517

1) Note that although load is interrupted above 50 MW, BVES can serve load up to 52.4 assuming 5 MW battery solution implemented.
Also , load can be served up to 56.4 MW for a duration of 3 hours. The load served above 50 MW has some degree of uncertainty.

To properly hedge the BVES load, BVES analyzed the hourly load patterns across the months under the Rivalry scenario with normal weather and with weather 25% colder than normal and 25 % above normal. The hourly load varies across the months due to tourism cycles, monthly weather cycles, DG solar generation pattern changes across the months, ski season traffic, and snow making patterns in the winter months. The hour patterns with in the months are impacted by the factors mentioned above. The supplemental sales to BBARWA and the Mammoth snow making load, and the battery duty cycle will contribute significantly to the changes in the hourly load patterns and the load levels beginning in 2020. Also, there is a significant variance in the hourly load across the months created by differing weather and economic cycles across the month. The weather is a significant driver of the load variance and colder than normal weather has more of an impact on sales and load than warmer than normal weather conditions. BVES must hedge the load requirement with contracts to support all the load levels estimated in the 25% colder than normal weather. Also the forecast experts call for significant increases in gas prices in the 2022 period as more expensive resources are called upon to serve the market. California has reduced the emphasis on gas infrastructure in the state and has put a moratorium on natural gas generation. Also the natural gas demand growth is driven by the export markets to LNG world market and Mexico, and this will put upward pressure on gas market prices. This trend along with gas infrastructure problems makes price spikes in power and gas more likely in California. California has already experienced this with the nuclear plant outage, Aliso Canyon reduced deliverable capacity, and the Transwestern and El Paso pipeline outage in January, 2018, resulting in price spikes. BVES is more likely to face this price spike with colder weather than normal. Also contributing to higher power prices are the increases in incremental capacity value and the increases in carbon allowance prices. In addition, the RPS portfolio requirement will put upward pressure on power prices due to the intermittence of solar and wind production. BVPP as a hedge is less likely due to higher gas prices.

BVES accounted for this price risk by determining the upper range in the hourly load patterns for the months in the near term forecast where the load is at least 90% likely to be below the upper range determined for each hour, for each month. This level was determined for 2019 to 2023 for each hour, for each month to determine contract hedging target levels. This would be used to size purchase power contracts for BVES. Table 3 below shows the target levels for the hedging contracts.

Table 3: Targeted Hourly Load Levels in MWh to Hedge Using Firm Power Contracts

	Adjusted Total Contract Level Purcl				New Contract	Existing EDF
	jan	**Feb**	**Nov**	**Dec**	**Annual**	**Existing Annual**
					12/2019-11/2024	1/2019-11/2019
HR1	39	37	35	39	**14**	**12**
HR2	39	36	34	39	**14**	**12**
HR3	39	36	35	39	**13**	**12**
HR4	39	36	36	39	**13**	**12**
HR5	39	38	36	39	**13**	**12**
HR6	39	39	36	39	**13**	**12**
HR7	39	39	37	39	**13**	**12**
HR8	39	39	38	39	**14**	**12**
HR9	39	37	37	39	**15**	**12**
HR10	39	35	35	39	**16**	**12**
HR11	39	34	35	39	**17**	**12**
HR12	39	38	36	39	**20**	**12**
HR13	39	38	35	39	**20**	**12**
HR14	39	36	34	39	**20**	**12**
HR15	39	36	35	39	**20**	**12**
HR16	38	31	31	39	**16**	**12**
HR17	39	31	32	39	**16**	**12**
HR18	39	32	33	39	**17**	**12**
HR19	39	34	34	39	**18**	**12**
HR20	39	31	30	39	**14**	**12**
HR21	39	35	30	39	**14**	**12**
HR22	39	34	30	39	**13**	**12**
HR23	39	34	30	39	**11**	**12**
HR24	39	39	35	39	**15**	**12**

This annual contract target levels are stated above. The winter seasonal contract target levels would be the difference between the target level for the winter months and the annual contract value. The contract levels are defined below.

Table 4: Seasonal Contract Requirement for 1/1/2019 to 12/31/2022

	adjusted seasonal			
	jan	**Feb**	**Nov**	**Dec**
HR1	24.6	22.5	20.2	24.6
HR2	25.0	22.3	20.0	25.0
HR3	25.7	22.9	22.0	25.7
HR4	26.1	23.4	22.7	26.1
HR5	26.4	25.8	23.0	26.4
HR6	26.3	26.1	23.3	26.3
HR7	25.6	25.6	23.7	25.6
HR8	24.8	24.8	23.4	24.8
HR9	23.6	21.4	21.5	23.6
HR10	22.8	19.1	18.9	22.8
HR11	22.5	17.3	18.2	22.5
HR12	18.5	17.8	15.9	18.5
HR13	18.8	17.7	14.4	18.8
HR14	18.6	15.8	14.1	18.6
HR15	18.7	15.9	14.3	18.7
HR16	22.5	15.8	15.2	23.1
HR17	22.8	14.4	15.3	22.8
HR18	21.8	14.7	16.1	21.8
HR19	20.8	16.0	15.3	20.8
HR20	24.9	17.3	16.0	24.9
HR21	24.9	20.8	16.0	24.9
HR22	25.9	20.5	16.4	25.9
HR23	27.5	22.7	18.7	27.5
HR24	23.7	23.7	20.0	23.7

To reduce BVES' exposure to price spikes and to secure lower wholesale power costs for over 36 to 59 months, BVES requested Commission approval in June 2013 of the Master Agreement with EDF and four products overall consisting of annual baseload (EDF), seasonal baseload (Shell), a physical daily call option (EDF) and resource adequacy ("RA," Shell).[1] The Commission approved the proposed contracts on December 4, 2014. On December 9, 2014, BVES executed the annual, seasonal and call option products which resulted in a January 1, 2015 start date for these products. BVES executed the RA transaction with Shell in January with a March 2015

[1] BVES had a Master Agreement with Shell already in place. It then negotiated another Master Agreement with EDF, and then secured four energy contracts, two each with Shell and EDF.

start date. The contract volumes are detailed in Section 2.G, Table 14. The physical call option and the annual baseload contract with EDF and the RA contract with Shell continue through March 2020 and through November 2019 for the annual contract.

On May 12, 2018 BVES requested proposals for an annual contract to begin in December 2019, for duration of 59 months, at the volumes stated above. The pricing, the quality of the bidders and products, and the turnout of bidders will determine if BVES pursues approval of the two finalists and the firm energy products with the Commission.

The proposed annual and seasonal contracts combined will hedge up to 90% of the load through 2024, and 2022 respectively. The BVPP provides a partial hedge for the remaining 10% as gas prices still drive the BVPP generation marginal power cost. The BVPP has an 8.4 MW capacity and can therefore provide hedge equal to the gas price plus transportation cost at the 12,900 BTU/KWh heat rate of the BVPP. Although this provides some protection, the BVPP supply price is subject to gas price spikes.

The CAISO Market Redesign and Technology Upgrade (MRTU) Tariff has been in operation since April 1, 2009. Overall, the CAISO markets have performed as designed. While some extreme prices have occurred due to actual system constraints, improvements in the market software and modeling of the grid have resulted in less frequent price spikes. The CAISO will likely continue to introduce new features and functionality over the next few years, some of which may affect BVES, such as the RA program and a possible CAISO capacity market.

Due to changes over time in the CAISO tariff, BVES has had to take a modified approach to fulfilling its RA obligation. It is not yet known if the CPUC will adopt BVES' changes in its RA and capacity counting conventions. In the meantime, BVES will continue to procure RA resources including a 15% reserve margin, and will use its BVPP as a "behind-the-meter," distributed generation resource that decreases BVES' RA obligation. Other options for reducing the RA obligations and the associated cost will include development of a BVES-owned 8 MW AC solar project, facilitating further renewable DG growth in the residential and commercial sectors, and development of a 5 MW / 20 MWh (4 hour) battery solution, both located at the BBARWA location. These sources of solar production will decrease BVES' overall load and therefore reduce the RA requirement for BVES. BVES is assessing the benefits of stored power via flow battery or Lithium ion technology as a means to manage its load profile and reduce peak load and therefore contribute to the RA requirement. Results of the preliminary analysis indicate that the battery solution would provide a reduction in the RA requirement, a daily arbitrage, an increase in capacity served, and other load shaping benefits. The annual revenue requirements which includes the cost of capital, depreciation, operation and maintenance expenses , administration expenses, and taxes would be reduced by the 30% Federal Investment Tax Credit on the capital investment if the battery project were co-commissioned with the solar project . The net savings would benefit all the BVES customers directly by reducing the supply cost of power.

With a ten-year contract for Renewable Energy Credits (RECs) in place, BVES anticipates satisfying its obligations under the Commission's Renewables Portfolio

Standard (RPS) program through at least the year 2021. This contract, approved by the Commission in July 2013, provides the flexibility needed to manage the current RPS requirements that ramp up from 20% of retail sales to 33% by 2020 and to 50% by 2030.[2] The rest of the RPS requirement will come from the BVES 8 MW facility at BBARWA which will generate 19,224 MWh per year over the period 2020 to 2028, the length of the IRP. This project will have a 30 year life, and the MWh of generation will qualify as local renewable energy meeting the RPS standards. BVES will evaluate the additional RECs required after the solar project is approved and will base the decision on the IRP for 2020.

BVES analyzed the market environment utilizing IHS-CERA's energy market, economic, and policy outlook for the California market region and the Los Angeles economy, a sales and energy requirement forecast model, weather data from 2006 to 2017, the residential customer saturation surveys, and the hourly load shape data by customer class from 2006 to 2015.

BVES tested a variety of supply options against the energy market probable outcomes to determine a robust strategy plan for Energy Resource Supply that would minimize the energy costs for BVES and create the most benefit for the customer using average total cost of energy, average fixed cost, and emission reduction measures to judge the outcome of the strategies against the forecast environment. The net present value of these benefits across the various forecast scenarios was used to select the optimal strategy that BVES should pursue to provide probable least cost and most benefit to customers. In this IRP, particular attention was made to assure that the GHG emissions resulting from BVES supply were below the targets set for BVES in the IRP standards determined for the California utilities this summer. From the analysis supporting this IRP, the following conclusions and possible options have been determined:

Conclusions

- The current transmission capacity contracted with SCE (39 MW), the generation capacity of the BVPP (8.4 MW), and the demand-side management (DSM) resources available from the interruptible customers (currently 12 MW) are sufficient to meet BVES' firm load requirements through 2024 under normal and colder than normal weather conditions defined as those experienced within the last ten years.
- BVES can meet the interruptible load from the A5 primary class, existing and supplemental load, with less than 5% interruption with the current supply in place. If BVES is successful in gaining approval for the solar project at BBARWA and the 5 MW/20 MWh battery solutions, BVES can meet the supplemental load serving Bear Mountain Ski resort and the BBARWA waste water facility with no interruption to Bear Mountain Ski resort, barring a downed transmission line or BVPP outage.
- Model enhancements and a survey of customers provided significant support to the planning process, forecasting accuracy, and the ability for BVES to assess

[2] AB 350 was signed by Governor Brown in October 2015 and, among other changes, makes the 33% RPS a floor and not a ceiling and establishes a floor of 50% by 2030. See Chapter 3 for more information about the future of the RPS.

impacts of the residential and commercial customer DG program and the impacts of appliance and building envelope efficiency on BVES sales. BVES methodology for forecasting a method in line with other major utilities in the US and Canada.

- There is a significant uncertainty in the RA requirement given the uncertainty of the policy requirement for local and flexible RA for BVES, load-mitigating solar NEM/DG production, and the regulatory approval for the addition of a BVES-owned 8 MW solar facility directly connected to the BVES system, and the approval of a 5 MW/20 MWh battery facility. The supplemental sales to BBARWA and Bear Mountain ski resort which total approximately 20,000 MWh year beginning primarily in 2020 is highly likely however, it is not certain.

Options Being Considered

- Pursue the shaped power contracts for annual and base load based on the shapes derived assuming BBARWA and Bear Mountain incremental sales, the 8 MW solar facility build by 2020, DG and efficiency will continue to more than offset growth in retail sales, and finally a battery solution of 5 MW which reshapes the load significantly to allow for more capacity served. The bottom line is that the load and contract requirements have changed significantly since the last IRP in 2016 due to all changes stated above.
- Increase the daytime and summer load by offering customers an electric vehicle pilot program and eventually a special TOU residential and commercial rate encouraging use of electricity for transportation needs. The SCAQMD has selected Big Bear Lake to install two universal charging stations in the near future. Also the BVES Transportation Electrification Pilot project request has been filed, pending approval. The challenges of mountain elevation and snow conditions will be a barrier to overcome for BVES visitors. The incremental load for electric vehicle charging was not assumed in this forecast analysis.
- Energy efficiency trend already in place for residential and commercial customers will reduce annual retail sales from 4,000 MWh in 2018 to 16,000 MWh by 2028. This already has and will continue to reduce peak loads significantly as the lighting load is aligned with the system peak (7 PM to 10 PM at Christmas holidays). This should also allow more snowmaking energy sales relative to the capacity of the BVES system as Mammoth Resorts becomes more confident in BVES' capability to serve additional load without interruption.
- Add 8 MW of utility-owned solar generation to BVES service area via the BBARWA location project and continue to support solar DG using a tariff to compensate the customer at avoided cost for received power in order to reduce average energy cost, reduce average fixed costs by increasing daytime capacity, and reduce interruptions and air emissions. DG production is expected to grow from 5,800 MWh in 2017 to 18,700 MWh in 2028.
- Improve reliability of system and reduce price spikes via fuel and technology diversity in supply and increasing BVES local capacity relative to its total supply portfolio.

- Reduce BVES supply emissions to meet targets set by the California Air Resource Board in coordination with the California Public Utilities Commission, the California Energy Commission and reduce carbon emissions of the ski resort through BVES supplemental sales to Bear Mountain in place of customer using customer-owned diesel generators to make snow at Snow Summit ski resort.
- Monitor economic development trends in the BVES service area regularly in order to determine when it is appropriate to incorporate these developments into the sales and load forecast.
- Continue internal model improvements. Already have established Statistically Adjusted End Use models, DG capacity and energy production models, and financial evaluation tools for evaluating solar and battery projects.
- Continue use of customer surveys; use the survey data to build a forecasting tool for individual customers and therefore enhance the distribution planning initiatives.
- Enhance load research initiatives to better capture the changes to the load usage patterns of customers due to efficiency and DG production.

For the reader's benefit, because acronyms are frequently used throughout this IRP, a glossary of acronyms is included in Appendix F.

2. BVES Loads and Resources

2.A Description of BVES

Bear Valley Electric Service (BVES), a division of Golden State Water Company (GSWC), is an investor-owned utility (IOU). BVES provides electric service in a resort community to approximately 24,000 customers,[3] of which approximately 22,500 are residential customers with a mix of approximately 40% full-time and 60% part-time residents. Approximately 1,500 of the total number of customers are commercial, industrial and public-authority customers, including two ski resorts. This includes 425 net energy metering (NEM) customers.[4]

BVES' historical peak load is 45 MW;[5] winter monthly peaks occur when snowmaking machines at the ski resorts are operating and recreational visitors are present (generally between 5:00 pm and 11:00 pm on weekends). In the summer months, the load in BVES' service area ranges from an average minimum of about 11 MW (early summer mornings) to a maximum of approximately 24 MW (weekend holiday, mid-morning and late evenings).

BVES purchases wholesale power to meet the majority of its energy requirements. To aid in meeting peak demand for electric energy, BVES installed and now operates the Bear Valley Power Plant (BVPP), a natural gas-fired, 8.4 MW generation plant, with a tested heat rate of 11,500 Btu/kWh, in its service area. The BVPP became commercially operational on January 1, 2005.

BVES has two receipt points of power from Southern California Edison Company (SCE), the Goldhill transfer station and Radford Feeder. The majority of BVES' power is transmitted over SCE's 33 kV distribution line from the Cottonwood substation to the Goldhill transfer station. The remainder of BVES' energy is transmitted over SCE's 33 kV distribution facilities from the Zanja substation near Redlands, over the Radford Feeder to BVES' Village substation.[6]

BVES' distribution system is located and operates under the Balancing Authority of the California Independent System Operator (CAISO); however, BVES does not own any transmission facilities and is not a Participating Transmission Owner (PTO) under the CAISO Tariff. BVES facilities are indirectly interconnected with the CAISO-controlled grid via wholesale distribution access facilities owned, controlled and operated by SCE, that are then directly interconnected with SCE transmission facilities that are part of the CAISO-controlled grid. Lastly, the BVPP does not operate under a

[3] Based on number of active billed accounts as of December 2017.
[4] Includes systems under construction.
[5] The historical peak of 45 MW occurred on 12/26/2015. Prior peaks include 44.9 MW which occurred on December 31, 2014; 38 MW on January 12, 2013 and 44.6 MW on December 30, 2012. The last two years of peak occurred on 12/24/2016 and 12/16/2017 for 39.4 MWs and 40.5 MWs, respectively.
[6] BVES refers to voltages on these SCE lines as 34.5 kV.

Participating Generation Agreement (PGA) and thereby is not considered a CAISO controlled unit under the CAISO Tariff.

It should be noted that because GSWC is a holder of Congestion Revenue Rights (CRRs), BVES falls under direct tariff regulation by the CAISO. BVES must indirectly adhere to the CAISO Tariff due to power scheduling and RA requirements. The requirements are imposed on BVES by its third party schedule coordinator (SC),[7] who must abide by the CAISO Tariff to schedule BVES' power and RA resources.

2. B Summary of Loads and Resources

Tables 5 and 6 summarize the forecast of BVES' resources and requirements through the year 2028.

Table 5: Peak (MW) and Annual Load Requirement and Supply Hedge in MWh

			95th Percentile					Covers load above 39 MW		Increases Hedge Capability
Year	Peak MW	Annual Requirement in MWh	Annual Contract	Seasonal Contract	Total Contract	Total Short	BVPP Hours	BVPP Generation	Long Position	Battery Shift of Load
2011	40.1	152,027								
2012	43.6	146,236								
2013	38.8	150,133								
2014	46.4	145,768								
2015	46.0	150,388								
2016	42.7	156,258	105,408							
2017	42.7	161,565	105,120							
2018	42.7	152,018	105,120							
2019	45.3	158,931	118,540	68,600	187,140	8,524	76	638	28,848	7,300
2020	52.4	171,776	136,323	69,087	205,409	8,524	144	1,210	34,843	7,320
2021	52.4	170,267	135,950	68,600	204,550	8,524	136	1,142	35,425	7,300
2022	52.4	169,213	135,950	68,600	204,550	8,524	128	1,075	36,412	7,300
2023	52.4	168,702	135,950	68,600	204,550	8,524	126	1,058	36,906	7,300
2024	52.4	168,806	136,323	69,087	205,409	8,524	126	1,058	37,662	7,320
2025	52.4	169,633	135,950	68,600	204,550	8,524	258	2,167	37,084	7,300
2026	52.4	169,060	135,950	68,600	204,550	8,524	257	2,159	37,648	7,300
2027	52.4	168,598	135,950	68,600	204,550	8,524	254	2,134	38,085	7,300
2028	52.4	169,111	136,323	68,600	204,922	8,524	270	2,268	38,079	7,320

[7] Currently APX is under contract with BVES to act as its SC and provide schedule coordination services.

Table 6: Hourly Hedge Requirement Detail in MW

Hour	Hedge Requirement non -Winter Months	Hedge Requirement January	adjusted Hedge Due to Import Limit	Short Hedge for January	February Requirement	Adjusted February	Short Hedge for February	November Requirement	December Requirement	Adjusted December	Short Hedge December
1	14	46	39	7	37	37	0	35	47	39	8
2	14	45	39	6	36	36	0	34	47	39	8
3	13	44	39	5	36	36	0	35	46	39	7
4	13	44	39	5	36	36	0	36	46	39	7
5	13	44	39	5	38	38	0	36	46	39	7
6	13	44	39	5	39	39	0	36	46	39	7
7	13	44	39	5	40	39	1	37	45	39	6
8	14	45	39	6	39	39	0	38	42	39	3
9	15	45	39	6	37	37	0	37	41	39	2
10	16	43	39	4	35	35	0	35	40	39	1
11	17	41	39	2	34	34	0	35	40	39	1
12	20	44	39	5	38	38	0	36	43	39	4
13	20	43	39	4	38	38	0	35	42	39	3
14	20	43	39	4	36	36	0	34	42	39	3
15	20	43	39	4	36	36	0	35	43	39	4
16	16	38	38	0	31	31	0	31	39	39	0
17	16	40	39	1	31	31	0	32	41	39	2
18	17	43	39	4	32	32	0	33	46	39	7
19	18	45	39	6	34	34	0	34	48	39	9
20	14	45	39	6	36	31	5	35	49	39	10
21	14	46	39	7	40	35	5	35	50	39	11
22	13	44	39	5	38	34	5	34	49	39	10
23	11	46	39	7	39	34	5	35	49	39	10
24	15	45	39	6	41	39	2	35	49	39	10
Total	372	1,050	935	115	879	857	22	836	1,076	936	140

The annual peak and the annual energy requirement do provide insight as to the physical capacity requirements of the load. However, it is the hourly shapes that dictate the hedging requirement from contracts. The hourly load requirement was determined from the Rivalry (Base Case) scenario with weather that is 25% colder than normal. This weather event is very likely with the abnormal weather patterns experienced over the last 10 years. Under such a weather event, California is likely to experience gas and power price spikes. BVES will need to hedge against this occurrence. There is also a wide variance in the hourly load shape across the days of the months and the days of the week. Therefore the hourly hedge requirement was determined by taking the average hourly load and multiplying it by the t statistic for a 90% confidence interval. The product is multiplied by one plus the standard deviation of the hourly load for each month over the contract period. The result is an hourly load number that reflects a level where 90% of the hourly load observations will fall below that number. This insures that the hourly load would be properly hedged. The challenge is the transmission line from SCE to BVES capacity is limited to transmission capacity of 39 MW. That is the only contract supply line from CAISO to BVES. The result is that the contract has to be reduced to accommodate the SCE transmission line capacity limitation. This shortage is mitigated by the storage capability to transfer excess contract supply to hours where the contract supply is short. The contract supply is still likely to be long even after storage load shifting if BVES only subscribes to 5 MW of storage capacity. If only 5 MW of storage capacity is subscribed to, there will be a portion of the contract that will be sold back to the market. If more storage capacity is subscribed to, BVES could fully hedge the load and fully utilize the contract volume. Either supply solution is better than

BVES being short in a high price gas environment. Also, the gas fired generation unit can provide a partial hedge for power prices; however, the cost of BVPP power is tied to gas prices which should be higher and more volatile in the 2020s, especially with weather events. The BVPP does provide a volume hedge, but not an effective price hedge. The problem with using the BVPP as a price hedge, besides the higher gas prices is the high heat rate of 12,500 BTU/KWh and the high transportation rate for gas to BVES.

2.C Forecast of Load Requirements

2.C.1 Load Duration Analysis and Conclusions

After a careful review of the BVES system's peak load forecasts, it is concluded that even in extreme weather scenarios where capacity limits are approached, the duration of the peak load is very short-lived, 1 to 2 hours at most. Options, under consideration, include (1) reducing peak demand through continued support of lighting efficiency program for residential and commercial class, (2) interruptible tariff schedules, (3) water heater cycling, and spa cycling, which shift load usage by a few hours and even minutes to achieve the resource balance needed during peak hours. Because the efficiency programs sponsored by BVES have already targeted and implemented lighting efficiency for most of the large commercial classes, the hotels, larger restaurants, the major grocery stores and residential classes for the residential class with special emphasis on the low income who needed support implementing the lighting efficiency changes, the efficiency trend has been primed enough to allow the economics and technology changes to continue the efficiency trend. The efficiency trend has taken off significantly for the residential and commercial classes and already has had an impact on shaving the nighttime load, which is the time of the peak for BVES. Other appliances were retrofitted via the efficiency program such as water heaters; however, lighting offered the greatest load shaving benefit. BVES has discontinued the program as the efficiency equipment changes already have a significant benefit relative to the cost due to the higher electric rates in BVES and California relative to the rest of the country and the technology changes offered at a reasonable cost to consumers. The EIA forecast for lighting efficiency, window standards, appliance standards, and construction standards for home insulation has assessed a continuation of the strong impact of efficiency on commercial and residential energy consumption.

The strong growth in energy efficiency also ties with the adaption rate of distributed generation and battery solutions for customers. The stored energy technology in the residential and commercial sector offers a way for customers to maximize the benefits of solar generation in the home or business which is needed given that BVES has discontinued the Net Metering Program (NEM), and will be replacing NEM with another Distributed Generation Tariff for new subscribers. The new Distributed Generation Tariff will compensate customers for received daytime power at the avoided cost and not the full retail rate at all times of consumption. Energy revenues and not KWh costs will be netted; and therefore evening consumption will be more costly for the customer under the new Distributed Generation Program than under the Net Metering Program. The battery solution can minimize the cost of energy for the

Distributed Generation customer under the new tariffs; however, the consumption of power will be a target for efficiency changes in adapting the new Distributed Generation program in order to minimize the battery and the generation capacity. In other words, there are limitations on the capacity of the solar panels and there is a significant cost per KW of solar and battery capacity that incentivizes the customer to minimize energy usage where possible. Efficiency gains in the household and the business establishment meets that requirement very easily.

Energy efficiency changes are more likely to work as a solution for minimizing energy costs to BVES customers given that the Bear Valley Electric Service area is a tourist spot and has more visitors or non-permanent customers than permanent customers. Changing visitors' behavior while on vacation is not feasible. A BVES customer changing the technology to reduced energy consumption is more effective than BVES implementing a demand response program. This has been the case in residential and commercial establishments replacing light bulbs, installing light control switches, and using thermostat programs to control temperatures throughout the day. For this reason, BVES has allowed the efficiency and Distributed Generation to continue and has removed as options the efficiency subsidies and the demand response options.

Also under consideration at this time to manage the hourly load for BVES, is the application of Lithium Ion and flow batteries. The flow batteries are a family of battery chemistries including vanadium, redox, zinc bromine, and iron chromium in which a liquid electrolyte is cycled through an electron chemical cell. This battery system typically stores power up to 10 hours, and can store power for longer periods if necessary. The battery system would be used to condition the system load and reduce capacity requirements. Given the short duration of the top 5 MW of system firm load, the wide swings in the non-firm load shape, and the fact that this technology can store power for long durations, this technology could help BVES achieve the load conditioning required to significantly reduce capacity costs.

The Lithium Ion battery has a storage capacity of 3 to 4 hours and has a lower capacity cost than the flow battery. BVES hired Fractal Energy Storage Consultants to perform an engineering and financial analysis of the different battery solutions. Taken into account was the degradation of the duty cycles, the cost of replacing battery storage cells, the parasitic load of the battery, the benefit solutions of batteries, the feasibility of the optimization schedules of the duty cycle accommodating the benefits, and the 30 % federal tax ITC for batteries co-commissioned with solar projects. The largest benefit of the battery solution is the arbitrage value of supply purchases, the reduction in Resource Adequacy Requirement, the reduction of capacity cost for the SCE lines, and the reduction in interrupted retail sales. Benefits of the battery include the accommodation of the hedging of the BVES load by way of load shaping, and the accommodation of more renewables from customer owned Distributed Generation and utility owned solar, and therefore the reduction of carbon emissions from BVES power supply. BVES is further investigating the 5 MW / 20 MWh solution to reducing BVES supply cost by enabling a greater hedge in the energy requirements through fixed price firm power contracts.

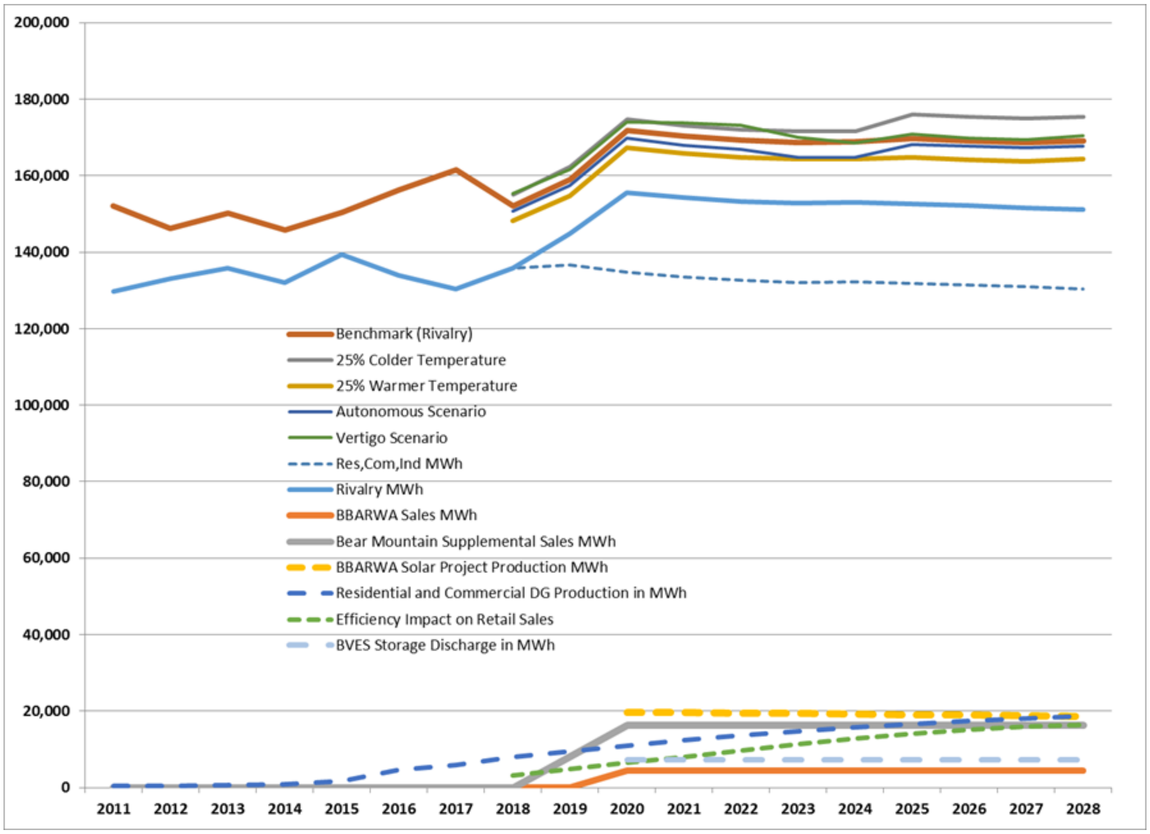
2.C.2 Base Case Peak Load Forecast

Please refer to Table 7 and Figure 2. Table 7 is the energy requirements across three scenarios. Energy requirements include the retail sales, taking into account the Distributed Generation impact on sales, grossed up for line losses. This is the energy requirement that BVES must supply. Figure 2 is a line graph where the top cluster of lines is the energy requirements. The middle two lines are the retail sales with supplemental sales and retail sales without supplemental sales. The bottom cluster of lines is the supplemental sales components, the solar production from utility owned generation at BBARWA site and the solar generation from residential and commercial customer’s roof top solar generation, and the impacts of efficiency on sales.

Table 7: BVES Net Energy Requirements across the Scenarios in MWh

Year	Net Energy Req. Benchmark (Rivalry)	Net Energy Req. 25% Colder Temperature	Net Energy Req. 25% Warmer Temperature	Net Energy Req. Autonomous Scenario	Net Energy Req. Vertigo Scenario
2011	152,027				
2012	146,236				
2013	150,133				
2014	145,768				
2015	150,388				
2016	156,258				
2017	161.565				
2018	152,018	154,985	148,227	150,635	155,380
2019	158,931	162,318	154,796	157,392	161,601
2020	171,776	174,791	167,335	169,725	174,090
2021	170,267	173,145	165,786	168,001	173,752
2022	169,213	172,042	164,765	166,904	173,176
2023	168,702	171,527	164,300	164,731	170,110
2024	168,806	171,652	164,457	164,780	168,540
2025	169,633	176,046	164,687	168,120	170,846
2026	169,060	175,411	164,159	167,611	169,792
2027	168,598	174,901	163,767	167,249	169,461
2028	169,111	175,369	164,316	167,795	170,465

Figure 2: Net Energy Requirements (Top Lines) and Retail Sales and Impacts (Bottom Lines) in MWh



BVES has a wide range of firm and non-firm hourly loads due to varying weather patterns, adaption rates of renewable distributed generation, environmental policies, trade policies, economic cycles, technology adaptions, and timing of hourly load relative to monthly sales. BVES sets a target hourly load forecast based on all the hourly load shapes observed across the years 2008 to 2015, with an emphasis on the more recent observed load shapes and the forecasted monthly energy requirements across the weather and net metering scenarios. A set of forecasts across with varying economic-environmental-trade policies (Rivalry, Autonomous, and Vertigo) determine where energy requirements will land in the future because these macro policies impact all utilities and energy suppliers. The benchmark case is the Rivalry case which is the middle forecast for economic growth, technology adaption, trade policies, and the environmental policies. The Vertigo scenario reflects a break down in open trade policies, a slowdown in technology innovation, a moratorium of some environmental policies, and most importantly a reduction in the growth in the solar Distributed Generation of residential and commercial customers. The Autonomous scenario reflects open trade, strong environmental policy, technology innovation, strong economic growth, and faster adaption of Distributed Generation and batteries by the utility customers. These three scenarios set milestones in the forecast. Note that the US will likely bounce around these three scenarios over the life of the project.

The weather scenarios were derived from the Rivalry case. These weather scenarios set likely boundaries to the energy requirement forecasts as weather will vary from normal weather conditions year over year. The weather scenarios include (normal, 25% colder and 25% warmer). From the scenarios, it was determined that the Rivalry with 25% colder than normal weather would be used to size the contracts.

From the forecast service IHS-CERA provides it is apparent that 2021 to 2024 could prove to be an inflection point for gas prices as the gas supply shifts towards dry and non-associated gas for supply sending gas prices to higher levels. This trend along with growth in exports to Mexico and the LNG export market will drive most of the growth in natural gas demand. With a strong push back from California from developing gas fired generation plants and nuclear plants and the gas pipeline infrastructure coupled with a strong policy push for renewables there will be significant drivers in play for higher prices, price spikes in both the power and gas markets. It is an unknown as to what the final levels for battery and solar will play out to be and what the price curves in the CAISO price shapes will look like.

The most vulnerable scenario for BVES would be the case of healthy growth in the economy and colder than normal weather, which is most likely to create an environment with price spikes in gas and power. High power prices would impact BVES supply cost if unhedged, also the BVPP power plant would not be a useful hedge because of the high heat rate in the plant (12,500 BTU/KWh) and the high natural gas prices because the BVPP is a gas fired generation unit. Also there is a high transportation rate for natural gas transported to Big Bear Lake for the BVPP.

BVES used the Rivalry scenario with 25% colder than normal temperature. BVES calculated the 90th percentile for the 24 hourly load periods for each month to determine a shape for annual and seasonal contracts for BVES to build a hedge. This would assure that BVES would not be short more than 10% of the time. BVES's storage solution can provide contracted load to short positions using the long positions that occur in the contract to supply the storage. This would allow BVES to be fully hedged on the price for all volumes served by BVES, without having to depend on the gas fired power plant, BVPP, for price hedging. The BVPP gas fired generation plant would only be used to support load above the import or storage discharge capability. This was decided to be best for BVES given the tight gas market and California gas infrastructure challenge along with the California RPS policy that will challenge supply in the power market and gas market conditions.

The high RPS supply percentage already creates vulnerability conditions for the CAISO market given the intermittent nature of the wind and solar facilities. Weather occurrences can significantly reduce the wind and solar power supply in any given day, putting pressure on the gas market to supply fuel to the gas fired generators with fast ramp up capability.

Already in January, BVES faced high gas and power prices due to the gas pipeline capacity reduction at Transwestern and El Paso pipeline entering the Southern California border, the reduction in Aliso Canyon storage facility, and the nuclear plant outage in southern California. A cold snap with these conditions created the price spikes in SP15 power price point and the Southern California city gate price. These events are more likely to occur more in the 2020 to 2028 period of the IRP planning period; therefore, BVES must be conservative in the hedging position and hedge at the 90% confidence level for each hour using the Rivalry scenario with 25% colder weather. Please see Table 8. Although there is a significant variance in the energy requirement across the scenarios and the growth in energy requirements is significant as Mammoth supplemental sales and BBARWA sales take hold, the peak load forecast variance between peak loads is constrained by the capacity limits of the system and the battery discharge.

Table 8 below is the peak load forecast which does not change after 2019 due to the capacity limits. The capacity components is 34 MW at Goldhill Transmission Line , 5 MW at Radford, 8.4 MW from BVPP, and 5 MW battery discharge.

Table 8: BVES Peak Load Forecast Across Scenarios in MW

Year	Benchmark (Rivalry)	25% Colder Temperature	25% Warmer Temperature
2011	40.1	40.1	40.1
2012	43.6	43.6	43.6
2013	38.8	38.8	38.8
2014	46.4	46.4	46.4
2015	46.0	46.0	46.0
2016	42.7	42.7	42.7
2017	42.7	42.7	42.7
2018	45.3	47.8	42.5
2019	52.4	52.4	52.4
2020	52.4	52.4	52.4
2021	52.4	52.4	52.4
2022	52.4	52.4	52.4
2023	52.4	52.4	52.4
2024	52.4	52.4	52.4
2025	52.4	52.4	52.4
2026	52.4	52.4	52.4
2027	52.4	52.4	52.4
2028	52.4	52.4	52.4

Please refer to Table 9 below. Although the peak levels are relatively stable, the hours of load above 40 MW should significantly increase as the BBARWA and Snow Summit, Mammoth, supplemental loads take place. Also growth in the exiting A5 primary rate class for snow making will provide a boost to energy requirements. Also refer to Table 2, which has the hours above a variety of MW thresholds in the BVES energy requirement. Both these tables indicate that the supplemental loads coming on line need the storage charging in the daytime to supplement the nighttime capacity required at higher MW levels in the firm hedging contracts than what BVES subscribed to in the past.

Table 9: Hours Where BVES Load is Above 40 MW

	hours of +40 MW	hours of +40 MW	hours of +40 MW
Year	Benchmark (Rivalry)	25% Colder Temperature	25% Warmer Temperature
2011	1	1	1
2012	14	14	14
2013	0	0	0
2014	33	33	33
2015	49	49	49
2016	13	13	13
2017	13	13	13
2018	34	63	9
2019	244	337	176
2020	433	545	321
2021	417	528	306
2022	402	516	296
2023	399	508	293
2024	397	509	292
2025	597	879	452
2026	598	887	455
2027	593	868	446
2028	608	881	453

Other solutions under consideration but not included in the most likely case are as follows:

1. Utility-sponsored residential lighting efficiency program targeting all residential lighting bulbs above 9 watts. This has a load reduction potential of 9.5 MW.
2. Proposed demand response programs for water heaters and spas could also reduce total system peak.
3. Enhance the current import capacity by 1-2 MW at a fraction of the cost of other supply alternatives would involve reconfiguring BVES' distribution system by adding circuits to the Radford line during winter months.

All of these options will be assessed based on the benefit to the customer. Lighting efficiency has already taken off a significant portion of load and will continue to shave load. BVES does not have to continue to subsidize this growth in efficiency because the market and the government policies already will stimulate the efficiency impact growth in the forecast horizon. Efficiency programs for low income population BVES customers will continue.

Demand response programs are not as effective in tourist locations as efficiency equipment installations. Lighting and appliance efficiency changes and autonomous light switches have been more effective in reducing energy consumption during the night time peak hours at BVES.

Adding circuits at Radford is already under consideration along with other options. BVES included this enhancement by assuming full capacity utilization of Radford and Goldhill, equal to 39 MW to serve the BVES hourly load. The exact technology to achieve this is still under investigation.

Capacity expansion is not required to serve firm peak load over the forecast horizon of 2018 to 2028. This includes the supplemental BBARWA sales. BVES can meet the entire interruptible load with interruptions less than 5% of the time. This includes the additional supplemental capacity to serve Snow Summit of 13 MW. The storage solution can eliminate the need for interruption. With the growth, a higher level of hedging is required to protect against price spikes. The battery solution enables BVES to smooth BVES hourly load to fully utilize the hedging contracts, which may be fixed volume, variable volume, and shaped contracts. The pricing outlook for power and gas sector makes this requirement more apparent in this outlook from 2018 to 2028.

2. D Forecast of Energy Sales

2.D.1 Retail Sales Trends

BVES' annual retail sales remain below the all-time sales achieved in 2006. Energy sales declined in 2007 and continued to decline significantly through 2010. While the national economic recession was partially the cause, the decline in real estate values had a major effect on the growth of the Big Bear economy and local activity. With the recovery in the economy and real estate more pronounced in 2012 and continuing through May 2015, BVES sales have increased from the 2010 levels. In 2014, BVES sales were 7.3% short of the peak sales in 2006 while 4.4% higher than the trough in 2010.

The peak in sales due to demographic and economic activity occurred in 2006, reaching 148,436 MWh. Sales then declined, hitting a low in 2010, of 129,583 MWh. As incomes in the Log Angeles-Long Beach-Santa Anna metropolitan statistical area (MSA) continue to increase, the real estate and tourism industries see growth in the BVES service area and, therefore, result in increased electricity sales.

All along efficiency gains have continued to shave retail sales growth. Also, net metering production from the residential and commercial sales class began to solidify and surpassed the 1,000 MWh of production the latter half of 2014. By 2015 the Net Metering production hit the 1,800 MWh level and began to grow more rapidly, hitting a level of 5,800 MWh by 2017. This growth was stimulated by the NEM tariff structure which compensated received power from the customer at full retail rate. It was also stimulated by the 30% federal government investment tax credit, the high retail rates (relative to national average), the reduction in the cost of solar panels, and the solar initiative program in 2014 which subsidized the solar panel capital investment. This trend along with energy efficiency reversed the growth in sales trend by the end of 2015. Retail sales growth has declined significantly from 2015 to 2017.

Although the retail sales inflection point of 2006 was led by the residential and commercial, firm sales class, the volatility of sales has been driven by the A5 primary (non-Firm sales class). This class is driven by snow making activity which can vary as much as 40% in a year. Temperature variation, winter skiing activity, economics of running the ski resorts (Bear Mountain, Snow Summit) dictate the amount of snow making and therefore the amount of A5 Primary sales each winter season.

Figure 3: BVES Retail Sales History in MWh

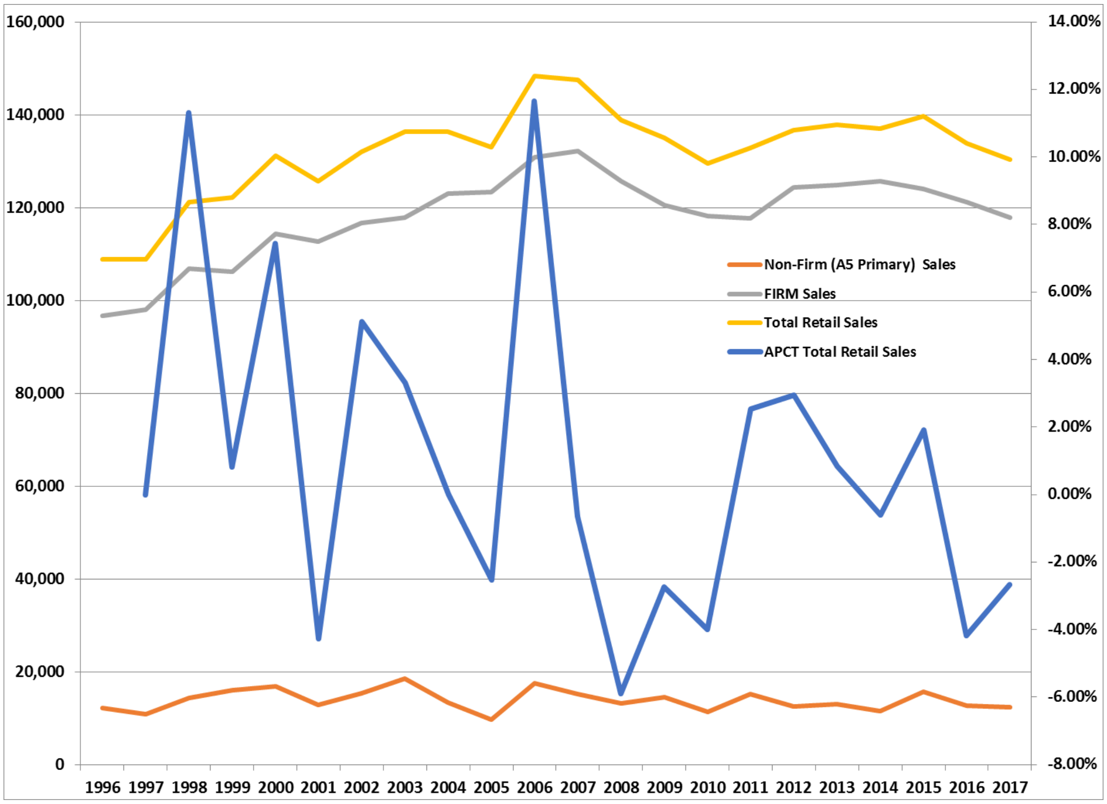
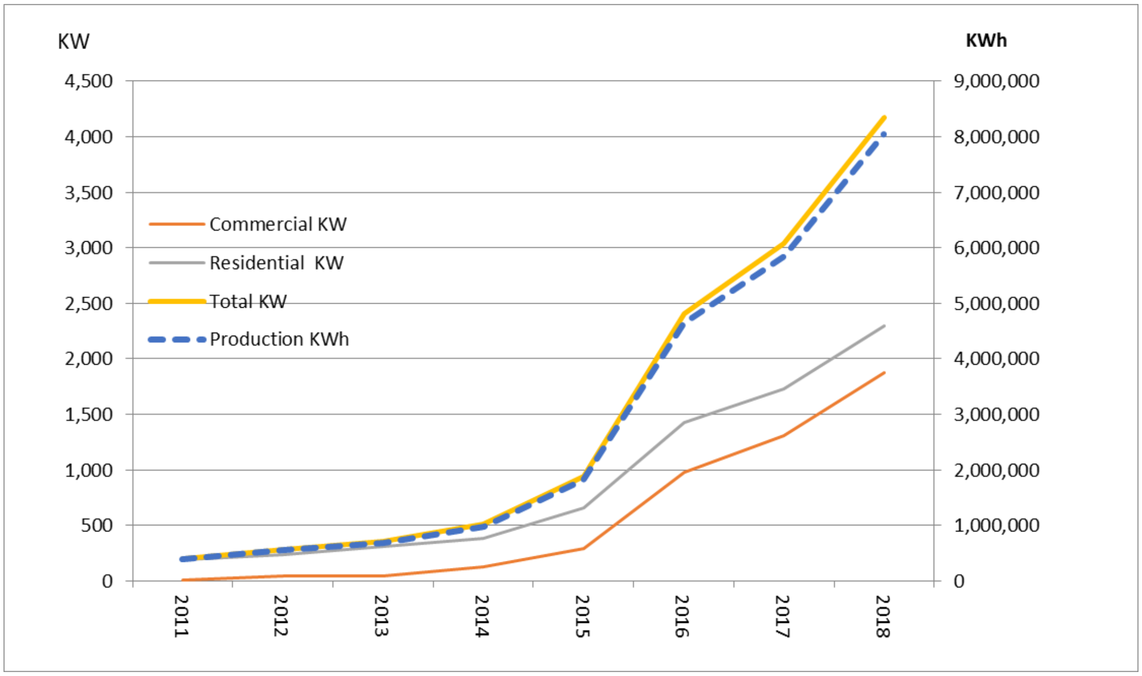


Table 10 Retail Sales History Firm and Non-Firm in MWh

Year	Non-Firm (A5 Primary) Sales	FIRM Sales	Total Retail Sales	APCT Total Retail Sales
1996	12,235	96,646	108,880	
1997	10,854	98,004	108,858	-0.02%
1998	14,297	106,868	121,166	11.31%
1999	15,967	106,182	122,148	0.81%
2000	16,841	114,381	131,222	7.43%
2001	12,919	112,696	125,615	-4.27%
2002	15,333	116,707	132,040	5.12%
2003	18,582	117,826	136,408	3.31%
2004	13,415	123,006	136,421	0.01%
2005	9,623	123,331	132,955	-2.54%
2006	17,532	130,904	148,436	11.64%
2007	15,271	132,202	147,474	-0.65%
2008	13,115	125,674	138,789	-5.89%
2009	14,528	120,460	134,989	-2.74%
2010	11,385	118,198	129,583	-4.00%
2011	15,257	117,609	132,866	2.53%
2012	12,448	124,319	136,767	2.94%
2013	13,108	124,796	137,903	0.83%
2014	11,456	125,619	137,075	-0.60%
2015	15,702	123,996	139,698	1.91%
2016	12,693	121,179	133,873	-4.17%
2017	12,361	117,938	130,299	-2.67%

Distributed Generation by residential and commercial customers has contributed significantly to retail sales declines as both residential and commercial class have engaged significantly to the NEM program .

Figure 4: NEM KW and KWh History



Demand for electricity is a derived demand; that is, consumers do not buy electricity in and of itself. Instead, consumers buy goods and services that require electricity. BVES saw the impact of the real estate boom in California through 2007, after which the real estate sector began to crumble. BVES' service territory was particularly distressed because many homes are second homes and are expendable when real estate markets decline. This was reflected in the residential sales from 2007 to 2010. Big Bear Lake was especially hard hit economically as an area dependent on discretionary income of the Los Angeles-Long Beach-Santa Ana MSA. A healthy recovery has continued since 2010 with a moderate decrease in 2013, a stall in 2014 and strong growth in 2015.

Since 2006, renewable DG by residential customers through the net energy metering tariff has increasingly displaced retail sales. This became even more evident after the introduction of the Bear Valley Solar Initiative and the extension of the 30% Investment Tax Credit offered by the federal government to encourage solar production. The table below illustrates displaced sales by year.

Table 11: Retail Sales Displace by NEM Production

Year	Net Energy Metering Displaced Retail Sales (kWh)
2004	8,561
2005	32,618
2006	76,505
2007	95,659
2008	154,225
2009	190,077
2010	261,474
2011	402,300
2012	592,015
2013	714,369
2014	1,028,618
2015	2,255,334
2016	4,629,706
2017	5,846,732

The combination of customer generated solar power and the impacts of energy efficiency continued to dampen sales over the historic period.

2.D.2 Economic Structure of BVES' Service Area

The economic activities in the BVES service area depend mostly on recreation, food services and lodging, real estate and rentals. There is also a high amount of retirement activity in the service area, age 55 to 65. The percent of total employment in these industries and the retirement age population as a percent of total population are high relative to other major metropolitan areas in California.

There is a strong correlation between the BVES service area economy and that of the Los Angeles-Long Beach-Santa Ana MSA because 85% of the non-permanent residential customers reside in the Los Angeles metropolitan area. Resurgence in the Los Angeles-Long Beach-Santa Ana MSA economy will have a positive effect on the BVES area. As personal income increases in Los Angeles Metropolitan area, so should real estate investment, recreational activity, lodging, restaurants, and retail activity for the BVES area economy, which in turn stimulates other commercial and residential activity for the local economy. Personal income for the Los Angeles-Long Beach-Santa Ana MSA reflects the wages and salaries of the area along with proprietors' income, real estate returns, stock market returns, and additional income received by retirees and government aid recipients. As these income sources increase, so should interest in activities in the BVES area.[8] The Los Angeles-Long Beach-Santa Ana MSA economy is in turn dependent on the national and California economy.

[8] The electric sales forecast for BVES' service area is tied to the forecast of variables of the LA-Long Beach-Santa Ana MSA, provided by IHS-CERA, a vendor of economic and financial data forecasts.

2.D.3 Macro Economic Outlook

The U.S. economy[9] grew moderately in 2017 and is projected to maintain that trajectory in 2018 and beyond due to a variety of factors:

- The abundance of natural gas and oil made available through the rapid advancement of resource extraction in the shale regions provides a boost to the whole economy via increase in disposable income ($1B / $.01 drop in gasoline price).
- The "mature" status of shale natural gas production has reduced gas prices to the $3.00-$3.50 per MMBtu range over the long term (2016 to 2024), allowing the petro-chemical and primary metals sector to grow.
- Jobs have increased significantly across many sectors of the U.S. economy, created both directly and indirectly by the increase in production activity of the natural gas and oil industry (3 million by 2020). . Positive surprises on the reserves measurements for gas should add to the production capabilities for both oil and gas.
- The information technology boom continues, benefiting the California economy, and spanning many regions of the U.S.
- An increase in automobile sales occurs as pent up demand is released.
- The housing industry experiences a strong recovery due to low mortgage rates, housing price equilibrium, economic recovery, and the baby boomer generation downsizing their homes.
- US households have worked through the debt bubble and consumption is driving the growth in the US due to increased optimism.
- Positive boosts over the near term include growth in the household formulation rate for age 21 to 35 population cohort, reduced corporate tax rates, and regulatory role backs.
- Risk to growth include the US and Global political risk which may stifle capital investment.
- Labor shortage continues to be concern as unemployment rate hits all time low in many regions.
- Regions with younger populations, educated populations, and which provide tourism, such as California, have seen faster growth than other regions.
- Services and education sectors are growing strong, especially in the California region.
- Tourism, construction, real estate, younger population, and education will drive the California economy.

In addition, the US economy is growing without help from exports as China, Europe, Mexico and Canada face weaker economies. Although the economic slow-down in China has challenged the commodity industries (energy and metals), all major suppliers will make adjustments and revisit strategies in order to maintain growth in production and maintain market share. Movement away from price collusion and towards open competition should maintain health in the commodity industry. There is a new order in

[9] From IHS-CERA's *US Markets: An Executive Summary of Regional Economies*, Winter 2015, IHS-CERA *Spring Energy Series for 2016*.

the oil industry as suppliers view market share as being more effective than reducing production to manipulate oil price. Supply cost reduction through innovation and new allies in supply projects could set lower oil industry prices resulting in strong growth and benefits to all consumers. The natural gas industry continues to make technology and drilling strategy enhancements and invest in the infrastructure to bring gas to markets. Already demand for gas has increased significantly as gas-intensive manufacturing expands in the US. As supply adjusts to these changes, the demand will increase as commodity intensive industries benefit from sustained lower prices.

The California economy has maintained strong growth throughout 2013 to 2017, ranking 10th out of 50 states. California continues to grow faster than the U.S. as a whole because of growth in technical services, biotech, entertainment and related services industries, apparel manufacturing, housing construction, transportation, transportation materials, population growth, venture capital availability, and renewable product manufacturing. The highly educated work force in combination with venture capital availability continues to boost economic growth in burgeoning industries for California. The drought in California has dampened growth to some degree, impacting the agriculture industry severely. Water availability will have to be managed as droughts occur, but urban sprawl will continue to challenge water supply even in less severe drought conditions. In addition, exports have suffered due to the significant slowdown of the Chinese economy.

Although California has seen loss of population from US citizens leaving California to work in Texas and other regions of the US with lower tax rates and lower cost of living, there has been an increase in in-migration of people, young and educated, from all parts of the world to live in California. These immigrants have brought new venture capital to California as well. This influx of people and venture capital will also provide a boost to California economy.

The two figures below indicate employment momentum for regions across the US and for the Pacific Region states, which includes California. These figures show year over year growth in the horizontal axis and the last 3 months of growth in the vertical axis. The diameter of the spheres reflects the relative employment sizes of each of the regions. Spheres to the upper right hand portion of the graph reflect regions that are not only growing faster over the last year, but also indicate regions whose growth is accelerating. Both the Mountain and the Pacific regions show accelerating high growth in the economies. California economy is also showing accelerating employment growth over the recent history. This all supports growth in the BVES service area economy. The growth in California economy will support growth in the Los Angeles Economy and will therefore support growth in the Big Bear Lake tourism, real estate, and the early retirement population growth. This in turn supports retail sales growth for BVES.

Figure 5: Employment Growth by Region 3 Month and Year over Year

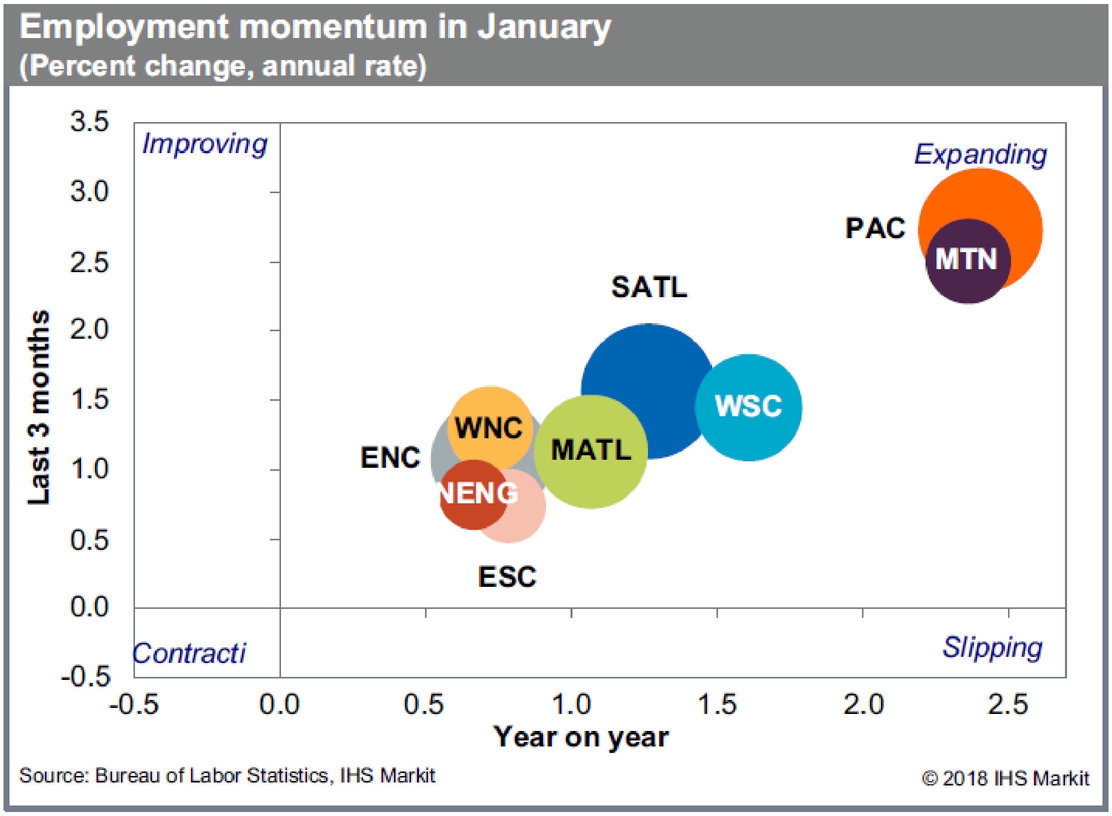
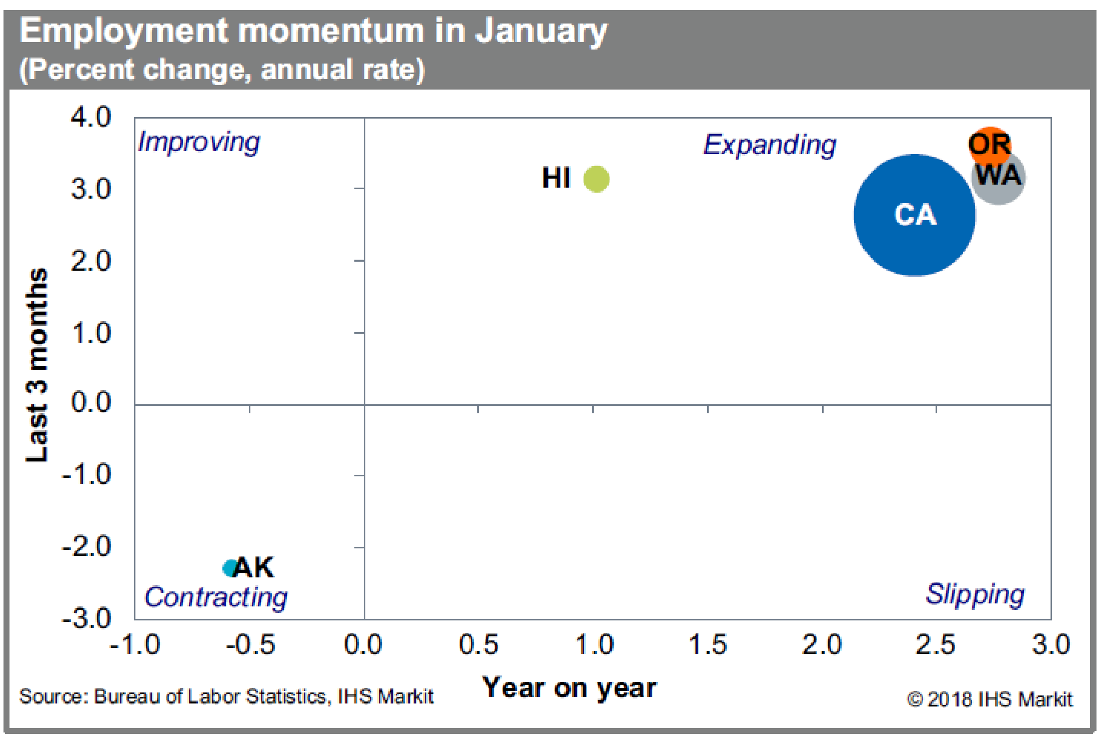


Figure 6: Pacific Region Employment Growth Momentum



2.D.4 Factors Affecting Wholesale Energy Prices

Drought creates a challenge for the power industry in California as the majority of gas fired generation requires water for cooling. Although water usage is restricted, the price of water is not yet high enough to fund water supply growth opportunities such as seawater desalination projects. Water restrictions can dictate power dispatch options and therefore increase prices as much as \$8.00/MWh, according to IHS-CERA.[10] A more favorable solution for the power industry might involve dynamic water pricing that would then allow generators better dispatch options. The resulting impact would likely cause only a \$2.00/MWh increase in prices. The power industry's marginal revenue product for water is estimated by IHS-CERA to be \$26,000 per acre-foot whereas the marginal revenue product for the agriculture industry is \$2,000 per acre-foot. As a result, there is an opportunity for the trading of water rights between the agriculture and power industries. Either restriction of water usage or water pricing could create upward pressure on wholesale power prices.

The boom in the natural gas industry in the U.S. will not only allow the country to be the top producer of natural gas and accelerate growth, but will also allow California to receive discounted gas prices in the market. The supply boom in the Northeast, Rockies, Texas, Louisiana, Arkansas, Oklahoma, and Alberta, Canada will "push" gas toward the West as suppliers compete for markets. The planned northeastern pipeline expansions will allow more Marcellus shale gas to enter the market, benefiting the whole US economy. Because gas-fired generation is a major source of electricity for California, the lower gas prices will put downward pressure on southern California power prices.

Also providing a boost in near term power supplies will be the increase in supply availability from Powder River basin coal inventories, which will in turn have a dampening effect on western market power prices. Renewables will continue to expand rapidly and provide a boost to power supplies, providing a hedge against reductions in hydro production due to drought. Gas fired generation will be an important energy asset to California as renewable energy is intermittent and only gas fired generation can ramp up quickly to follow load losses due to renewable power interruptions (i.e., cloudy days). Although stored energy does provide a solution to the intermittency of the solar load, there are still cost and technology challenges that limit the adaption rate of stored energy. BVES does see stored energy as a compliment to the renewable energy growth for the BVES service area and for California. However, gas fired generation will need to be part of the supply mix for California and for BVES.

Gas prices do face upward price pressure from a need for the traditional dry gas production basins, which is a more expensive option than the current wet gas, shale gas, and the associate gas plays. The major gas shale plays more recently face pressures for pipeline expansions from a cost of construction increase and environmental policy restrictions. Also the plays are experiencing sweet spot exhaustion. This will reduce the increase in supply from these plays at current low gas prices and will thus increase the

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[10] IHS-CERA, *Water Scarcity: What are the Potential Implications for U.S. Power Plant Economics?* Alex Klaessig and Meg McIntosh, December 2014.

market price of natural gas over the next decade. This in turn will increase the dry production plays in order to make up the supply shortage due to slow down in the associated gas and the shale plays. Adding to the gas price upward pressures is the continued rapid increase in LNG exports and US pipeline exports to Mexico. The LNG export growth adds another dimension to the higher gas prices over the next decade. The LNG exports in the winter are much higher and therefore support higher prices in the winter months, which is the prime season for BVES. The key uncertainty will be the price of oil and the impact it will have on associated gas. Much higher oil prices could sustain the associated gas play surge in the market and therefore would keep gas prices below at current low levels.

Another driver of gas demand growth for California markets will be the power demand sector demand growth resulting from 23 GW of power generation capacity that will be retired in western power markets by 2020 due to once-through cooling regulations.

Besides gas price increases in the near term, California power market also faces higher heat rates in the production of electricity from gas fired generation units. The growth in renewables, as California pushes forward on the Renewable Portfolio Standard requirement of 50% renewables in the supply mix of power by 2030 does increase the intermittency of the power supply and does create a ramp up requirement of gas fired generation as the solar sources of power fade in the waning time period of solar production. Faster ramp up requirement in the gas fired generation supply requires less use of less efficient gas fired engines and creates a higher average heat rate in the California power market. This trend along with higher gas prices will produce higher power prices for CAISO region and in particular for the SP-15 region, which serves BVES power needs.

The economic growth and fuel price assumptions used in this IRP forecast are listed in Table 12 and Figure 7 below.

Figure 7: Los Angeles Economic Drivers Regional Economic Drivers Indexed to 1990

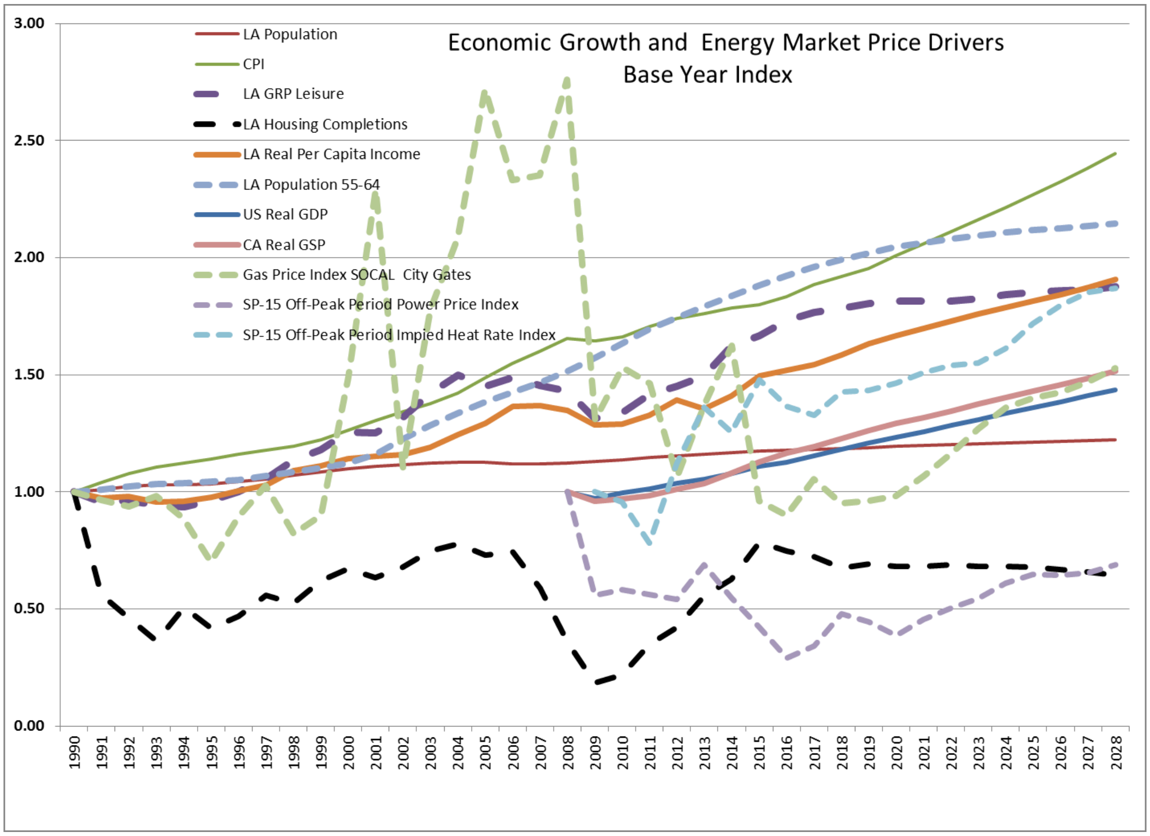


Table 12: BVES Economic and Energy Price Index

Year	LA Population 55-65	LA Housing Completions	LA Gross State Product (Leisure)	Equal Mix of LA Drivers	Gas Price Index SOCAL City Gates	SP-15 Off-Peak Period Power Price Index	SP-15 Off-Peak Period Implied Heat Rate Index
1990	1.00	1.00	1.00	1.00	1.00		
1991	1.01	0.56	0.96	0.84	0.97		
1992	1.02	0.46	0.96	0.82	0.94		
1993	1.03	0.36	0.94	0.78	0.98		
1994	1.04	0.51	0.93	0.83	0.89		
1995	1.04	0.42	0.96	0.81	0.70		
1996	1.05	0.47	1.00	0.84	0.89		
1997	1.07	0.56	1.06	0.89	1.03		
1998	1.08	0.52	1.14	0.91	0.82		
1999	1.10	0.62	1.18	0.97	0.90		
2000	1.12	0.67	1.26	1.02	1.49		
2001	1.16	0.63	1.25	1.02	2.29		
2002	1.23	0.68	1.32	1.07	1.10		
2003	1.28	0.75	1.42	1.15	1.78		
2004	1.33	0.78	1.50	1.20	2.08		
2005	1.38	0.73	1.45	1.19	2.72		
2006	1.42	0.74	1.49	1.22	2.33		
2007	1.46	0.59	1.45	1.17	2.35		
2008	1.51	0.36	1.43	1.10	2.76	1.00	
2009	1.57	0.19	1.31	1.02	1.31	0.56	1.00
2010	1.63	0.22	1.34	1.06	1.53	0.58	0.96
2011	1.70	0.35	1.41	1.15	1.46	0.56	0.78
2012	1.74	0.42	1.45	1.20	1.07	0.54	1.12
2013	1.79	0.55	1.49	1.28	1.37	0.69	1.36
2014	1.84	0.63	1.62	1.36	1.62	0.55	1.25
2015	1.88	0.79	1.67	1.45	0.96	0.42	1.48
2016	1.92	0.75	1.73	1.47	0.90	0.29	1.37
2017	1.96	0.72	1.77	1.48	1.05	0.34	1.33
2018	1.99	0.68	1.78	1.48	0.95	0.48	1.43
2019	2.02	0.69	1.81	1.51	0.96	0.45	1.43
2020	2.04	0.68	1.82	1.51	0.98	0.38	1.47
2021	2.06	0.68	1.81	1.52	1.07	0.45	1.51
2022	2.08	0.69	1.81	1.53	1.16	0.50	1.54
2023	2.10	0.68	1.82	1.53	1.27	0.55	1.55
2024	2.11	0.68	1.84	1.54	1.36	0.61	1.61
2025	2.12	0.68	1.85	1.55	1.40	0.65	1.72
2026	2.13	0.67	1.86	1.55	1.42	0.64	1.80
2027	2.14	0.66	1.86	1.55	1.47	0.66	1.85
2028	2.14	0.65	1.88	1.56	1.53	0.69	1.87

2.D.5 Additional Forecast Factors

In addition to economic growth and lower gas prices, the following factors should affect retail sales and have been considered in the forecast.

- Expansion of the ski resorts' snowmaking capability enabled by improvements to the existing substation which will add 1.3 MW to load capacity beginning in 2015 and anticipated substation expansion of 13 MW in winter 2019-2020. This could increase BVES sales significantly for the A-5 primary rate class.
- Impact of continuing California drought conditions on BVES service area economy, exacerbated by urban sprawl in Southern California, may continue to dampen sales.
- BVES' Net Metering program, which reimburses customers for their excess solar output at their applicable retail rate, should continue to grow due to the extension of the 30% Investment Tax Credit through 2020, and displace BVES electric sales. Beginning in 2015, Net Metering solar capacity and production increased due to the launch of the Bear Valley Solar Initiative, which funded a portion of installation costs. Although the Solar Initiative is no longer funded, it is projected that up to 12.4% of sales will be displaced by Net Metering activity by 2028.
- Electric Vehicle charging load initiated by EV charging installations funded by the SCAQMD in the near future, and a utility sponsored program starting the end of 2019, could add sales initially. Six to eight charging stations could be installed at locations in the Big Bear Lake Village, ski resorts, and BVES office by summer of 2019. A pilot project offering TOU incentive rates and commercial and residential make ready stations for customers have been requested by BVES to the Commission. This pilot project will aid BVES in evaluating the success of Transportation Electrification programs and the willingness of customers to shift their charging times to the daylight hours when solar production provides power on the BVES grid and the CAISO system. The level of uncertainty in the use of electric vehicles up in Big Bear Lake has led to BVES not including the Transportation Electrification load in the IRP forecast. BVES will review the pilot project results, if approved by the Commission and will make an assessment of electric vehicle charging load in BVES service area once the results of the pilot project are evaluated.

2.D.6 Energy Sales Forecast

Figure 8 illustrates the forecasted trend in BVES' energy sales. The system sales forecast without supplemental sales to Snow Summit or BBARWA represent the sales to firm and non-firm classes that result from economic activity , from normal activities, and assuming normal weather conditions. This projection does take into account the impacts of efficiency and the roof top solar production by the residential and commercial customers. This indicates sales growth should be non-existent as efficiency and customer solar production will erode normal sales growth from BVES. The two supplemental sales blocks which are likely to occur but require negotiated settlement agreements are the Snow Summit supplemental sales and the BBARWA sales, which could start in November 2019 and January 2020, respectively. These two blocks of sales reflect a step up in retail sales and not a growth trend in sales. Both Snow Summit and BBARWA are customers of BVES who have their own generation to support their energy demands. BVES is proposing replacing the 3 MW substation at the Snow Summit site with two 10 MW substations. This will allow the supplemental sales to Snow Summit for snow making activities, and avoid generation from Snow Summits diesel generation units. BBARWA gas fired generation supply will be replaced with BVES supply which will include solar production and BVES supply contracts through CAISO. Both of these initiatives require CPUC approval. BVES is requesting approval of the added facilities agreement with Snow Summit and will be requesting a special rate approval for BBARWA and approval of a utility owned 8 MW solar facility on the property of BBARWA.

Figure 9 reflects total retail sales forecast across the economic and policy scenarios (Rivalry, Vertigo, and Autonomy) and the weather scenarios (Normal, 25% Colder, 25% Warmer). The base case is the Rivalry case. The scenarios impact energy consumption and adaption of customer solar production. The uncertainty in the US economy, government policies, technology adaption, and weather require BVES to utilize scenarios in making supply decisions.

Figure 10 illustrates retail sales segmented into firm and non-firm sales and the supplemental sales assumptions. Note that the supplemental sales will be firm for BBARWA and will be non-firm for Snow Summit.

Figure 11 illustrates solar production by the residential and commercial customers of BVES. This production displaces the retail sales for BVES. The higher production in the forecast years is driven by the Federal Investment Tax Credit, the declining cost of solar panels, the compensation of received power from the customer to BVES, and the otherwise applicable tariff that applies to the BVES customer with the solar production facility. The scenarios dictate the magnitude of the solar production adaption by BVES customers through the cost of panel assumption. The Rivalry is the base case. The Autonomy reflects open trade and more adaption of solar panel technology, with increasing productivity of panels. Dampening the solar production forecast is the fact that BVES has discontinued the solar Net Metering Program with full retail rate compensation for received power and will be replacing the compensation for received power with an avoided cost, which reflects a lower compensation rate. The Vertigo scenario reflects restricted trade, higher cost of panels, and lower productivity of panels. The result of the scenario analysis is a wide range of retail sales displacement in the BVES retail sales forecast.

Figure 8: Total Retail Sales with Supplemental Sales Additions (Rivalry Sales Scenario)

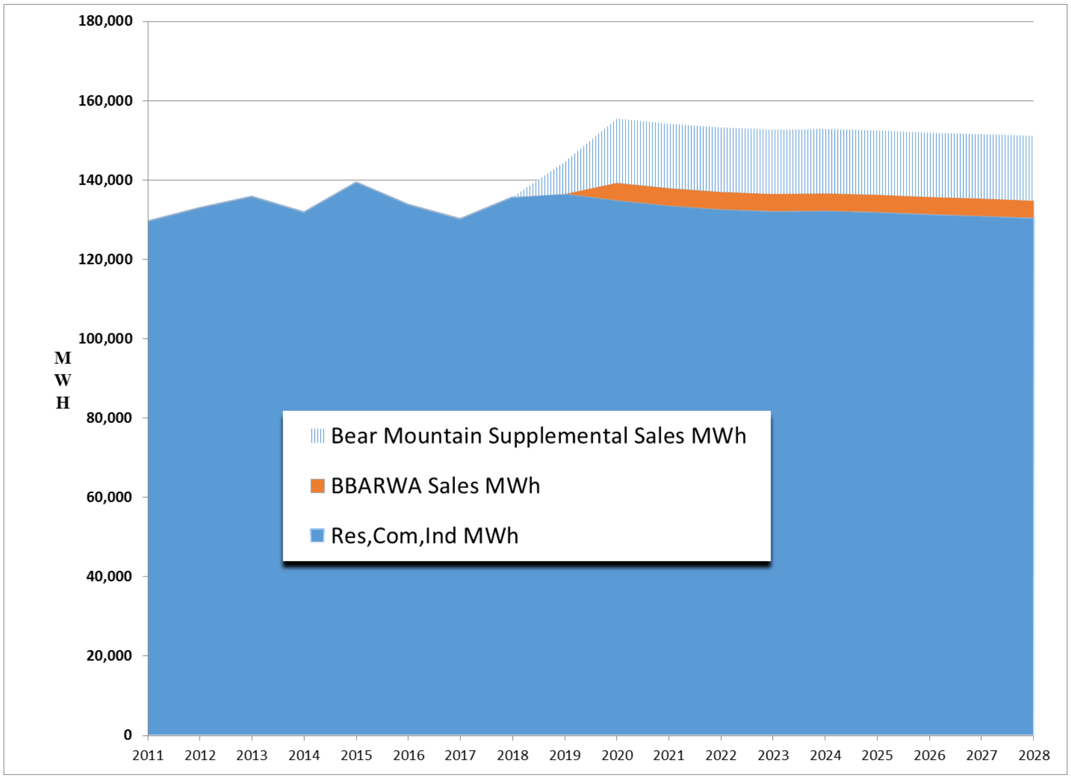


Figure 9: Retail Sales across Scenarios

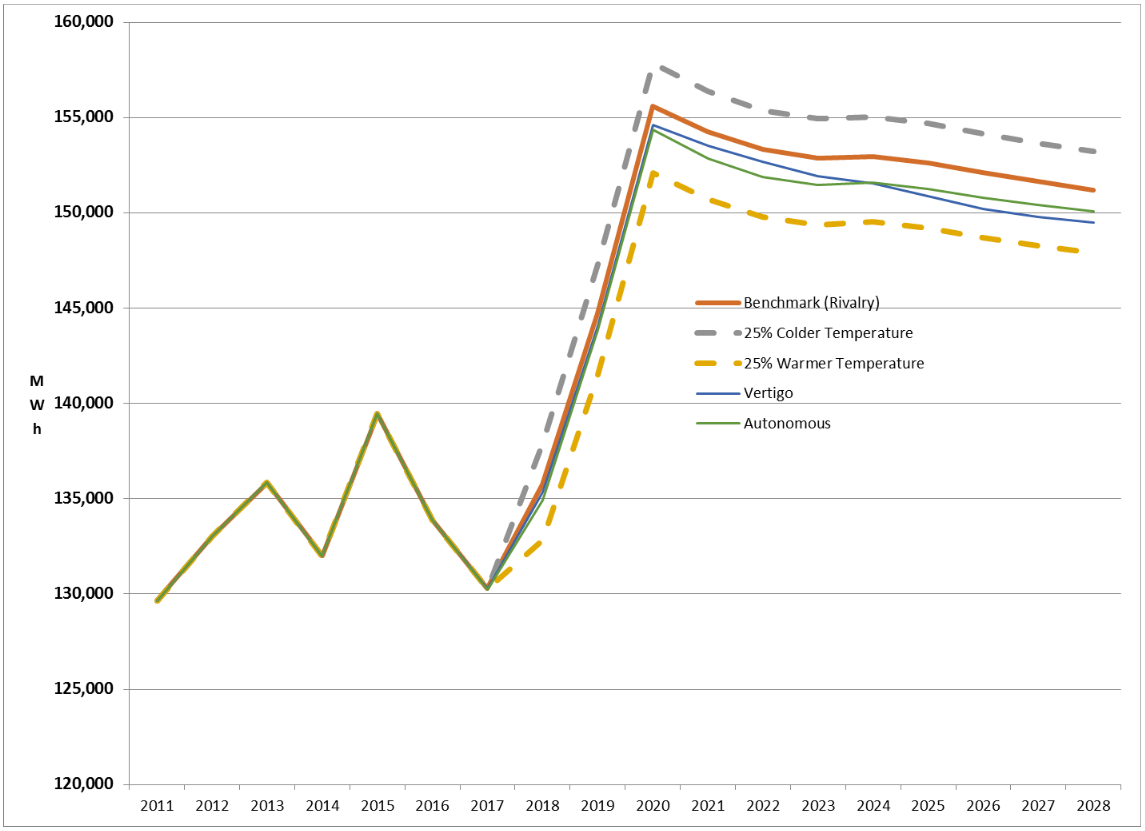


Figure 10: Retail Sales in Detail for Rivalry Scenario

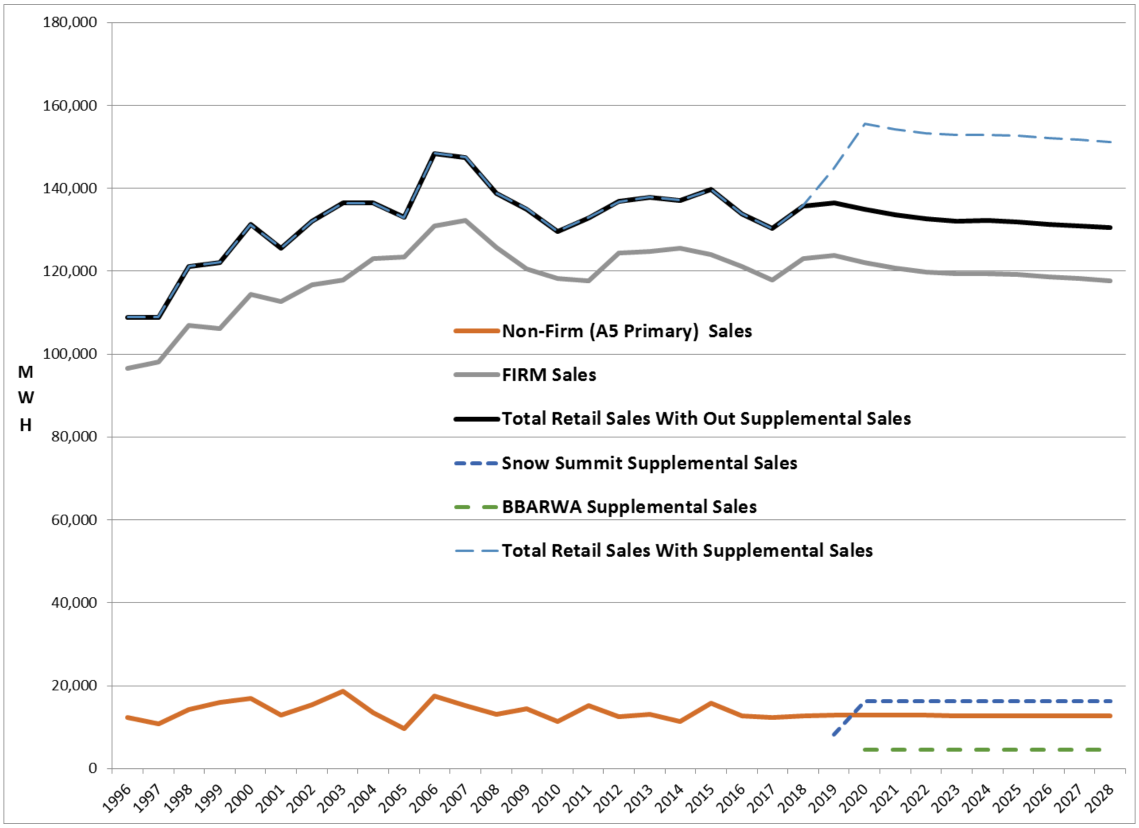
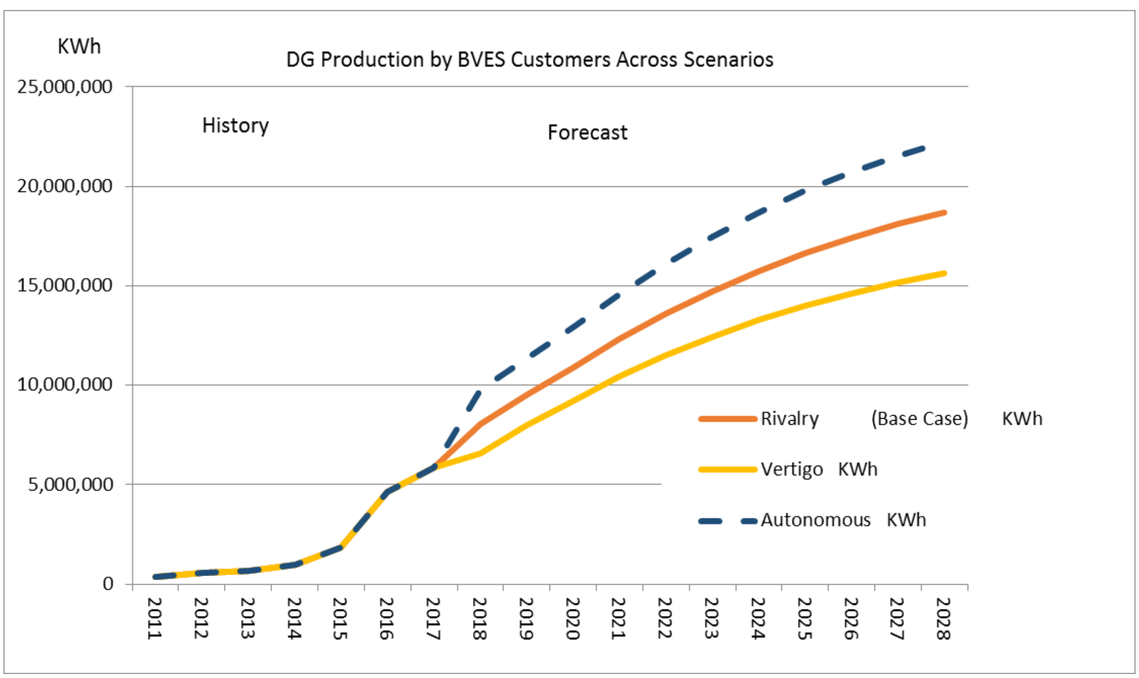


Figure 11: Solar Production by BVES Customers across Scenarios



BVES' energy forecasting methodology in this IRP began by using historic customer billing data from January 1996 through 2017. Past usage and customer counts were then used to develop models for residential, commercial, and industrial customer aggregations. Data were aligned with calendar months corresponding to monthly weather conditions captured by heating and cooling degree days.[11] A set of regression models was then used to forecast monthly demand and energy for the period 2018 through 2028.[12] This IRP forecast methodology differs from what was used in the past IRPs in that the model structure included the Statistically Adjusted End Model framework. End use EIA analysis of Pacific Region, with adjustments for local saturation rates of appliances, were used as drivers in the forecast of retail sales for the customer groups. This provided additional variables to the monthly type, weather, price, and economic drivers. Also the solar production variable was used in the models. This model framework allows for an explicit determination of efficiency and customer solar production on retail sales. As a check of the demand and energy forecasts, the capacity factor was also considered.[13] The load research sample data was utilized to derive hourly load shapes for each of the customer classes which results in an hourly load forecast based on those load shapes and the retail sales. The retail sales and the peak load are adjusted to reflect line losses in order to determine energy and load requirements for the IRP.[14]

2.E Summary Forecast of Demand and Energy

Figure 12 provides a summary of BVES' annual forecast for demand (peak load, MW, right axis) and energy requirements (MWh, left axis) across the various scenarios. All scenarios indicate growth in energy requirements in 2019 and 2020. This is the result of the sales increase stated in the section above. The energy requirements are losses plus the retail sales. The peak load does not have a distinguishable difference between the scenarios. This is because the system peak capacity of 52.4 MW collapses the difference between the scenarios. The system peak is the sum of 34 MW at Goldhill transmission line, 5 MW Radford transmission line, 8.4 MW BVPP, and 5 MW stored energy battery solution.

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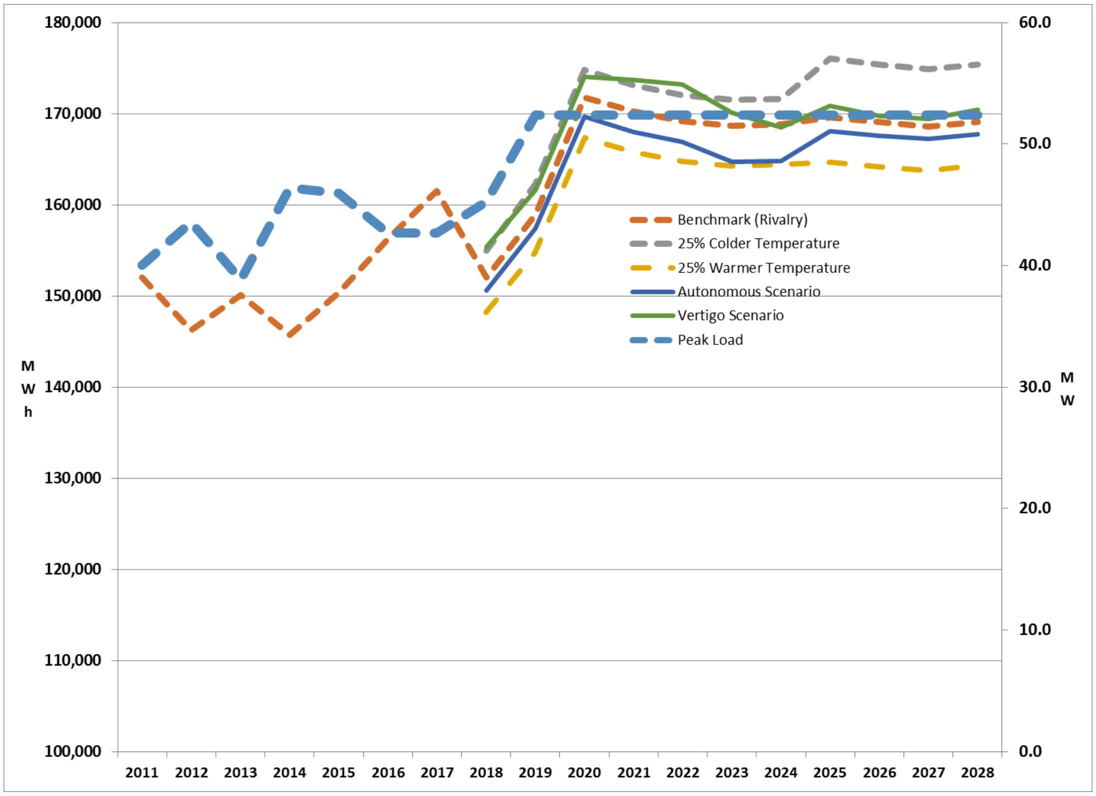
[11] Weather data was sourced from NOAA for the Big Bear Lake (station 40741) location.
[12] The forecast model for this IRP through 2028 uses real per capita income, real estate activity, retirement age cohort 55-65, entertainment activity, or transfer payments as economic drivers for some rate classes. The model also includes California's relative price of electricity as compared to the US.
[13] The capacity factor is the ratio of the electrical energy produced by a generating unit for a period of time compared to the electrical energy that could have been produced at continuous full power operation during the same period.
[14] The adjustment factor for line losses is 1.06442. For total losses, the adjustment factor is 1.137119.

Figure 12: Net Energy Requirements and System Peak Load across Scenarios



Refer to Figure 13. The composition of the system load under normal weather conditions is better defined viewing hours that the system load is above certain thresholds of MWs (10, 15, 20, 25, 30, 35, 40, 45, 50). The chart indicates that all hours have load above 10 MW. Most hours are above 15 MWs. At all MW thresholds, the hours increase by 2019 and 2020 due to the incremental load from Snow Summit and BBARWA as well as the battery duty cycle which would be charging during the daytime hours to discharge in the late evening time period, adding to BVES peak load capacity. This increase in hours across the higher MW thresholds indicates more utilization of capacity in the future. This also indicates that BVES will require a higher level of annual and seasonal power contract levels to hedge against higher prices end of 2019 into the future.

Figure 14 illustrates the composition of system load under 25% colder weather scenario. The impacts of the supplemental load and the existing load over the forecast horizon are more pronounced. This indicates the need for even higher firm power contract levels for all months. This is what BVES will use to frame the power contracts for volumes after 2019 because the power price levels will be higher and more volatile in a colder than normal winter and summer.

Note that although the A5 primary load and the Mammoth supplemental sales are interruptible, the load will have to be served if BVES system load is below capacity. All but about 5% or less of Mammoth snow making load will likely be interrupted.

Therefore, BVES must use power contracts to protect BVES customers from significantly higher prices from serving the incremental load.

Figure 13: Load Composition and System Peak: Normal Weather

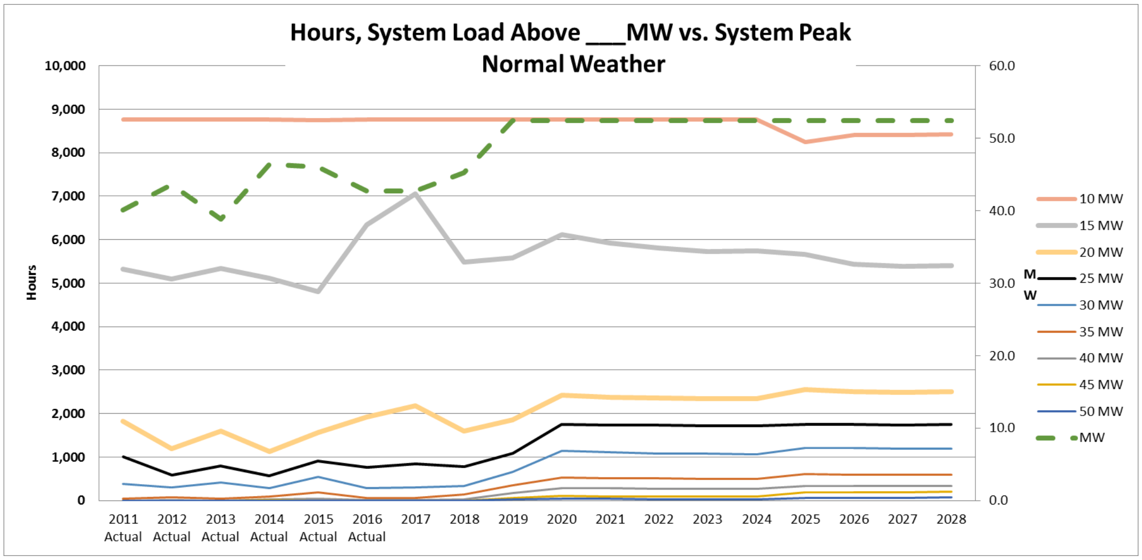
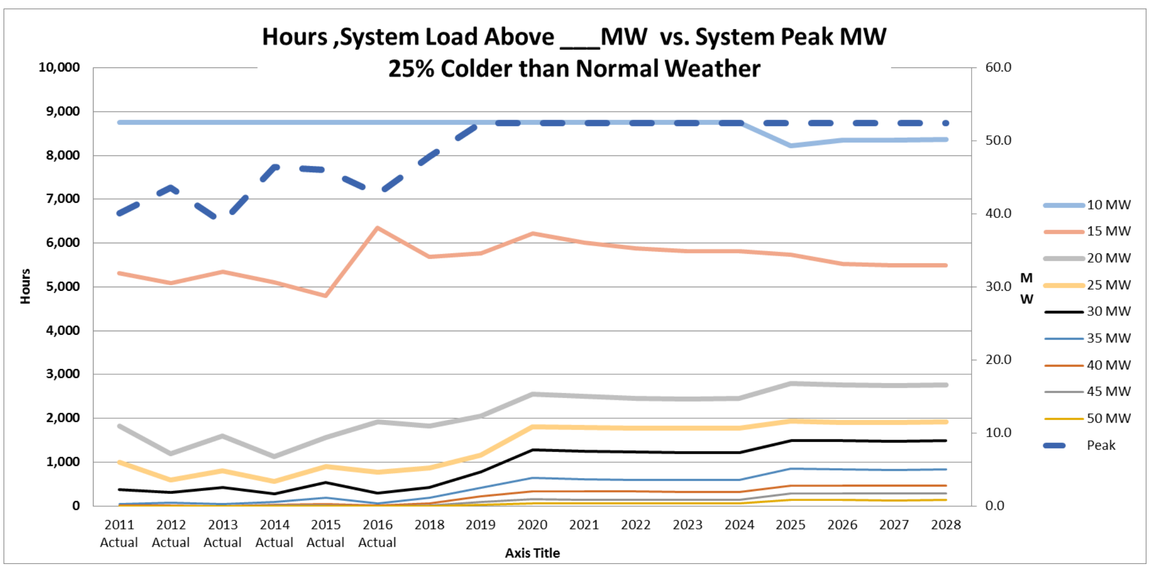


Figure 14: Load Composition and System Peak: 25% Colder Than Normal Temperatures



Weather also has an impact on firm sales, though mostly in the winter season as electric-driven heating load is required in the winter because most homes and commercial establishments have heaters and use electricity for ventilation of central heating system or space heating. The larger commercial establishments and some homes have air conditioning for warmer months; therefore, weather drives commercial sales year round. The summer air conditioning demand is somewhat diminished by the cooler nighttime temperatures in the summer. Lighting load is impacted to some degree by weather as the colder temperatures result in more daytime hours spent indoors, creating more lighting demand in the winter. Because most homes are not air conditioned and have heating fueled by gas, there is a wide range between the average temperature case and the minimum case and the maximum case.

Because a significantly larger portion of sales occur in the winter season between the Christmas and New Year's holidays, there is a higher coincidence in the customer class loads during this period in a colder than normal season which results in a higher peak load forecast due to sales effect and coincidence factor increase. Also, in general, there is more of a coincidence between snowmaking and the other classes during a colder than normal winter season; this can push up peak demand for the BVES system. Therefore, there is more of a peak demand response due to weather than the energy sales response due to weather.

In a milder than normal winter and the resulting lower amount of electricity usage for snowmaking, there is more of a divergence of the peak load patterns between classes. The peak load for the low case is significantly lower than the high case and the difference in the peak load is more pronounced than the difference in the energy sales between the high and low scenarios. The low case weather conditions actually shift the timing of the system peak load into early January as opposed to late December for the base case or the high case.

BVES' wholesale energy requirements, as measured by the meters at the two SCE receipt points, include retail sales plus SCE distribution feeder losses and BVES system distribution losses. BVES system losses are approximately 14 percent.[15]

Under certain high loading scenarios, BVES may experience capacity deficiency. In order to mitigate interruption and obtain best-fit, least-cost supply while considering the loading order,[16] the following capital investment scenarios are under strong consideration and BVES is seeking CPUC approval:

- Further invest in an energy efficiency public purpose program which targets residential lighting in order to reduce load during the critical peak period of 7 to 10 PM during the winter hours.
- Seek CPUC approval for 8 MW Solar single axis tracking system facility on the Baldwin Lake dry lake bed property (BBARWA) of 60 acres.
- Invest in an electricity storage system of at least 5 MW with 4 hour storage capability to balance the system load and accommodate more sales given the same level of capacity.
- Enhance the current import capacity by 1-2 MW at a fraction of the cost of other supply alternatives would involve reconfiguring BVES' distribution system by adding circuits to the Radford line during winter months.

[15] Based on a study for BVES using 2009 data. The BVES distribution system includes 4 kV and 34 kV systems, and the losses cited include both SCE distribution system losses and BVES system losses.
[16] See Section 5.C for a more detailed discussion on the loading order in California.

Further explanations of the possible capital projects and the potential benefits of those projects are provided in Section 5.E, Possible Capital Projects, in this IRP.

2.F Current and Planned Resources

2.F.1 Background

As a result of a competitive bidding process, in August 2008 BVES entered into a master power purchase agreement (PPA) with Shell Energy North America (US) L.P. (Shell) and subsequently executed four separate confirmation agreements for four distinct products with delivery dates commencing on January 1, 2009. The four products were annual baseload energy, seasonal baseload energy, a heat rate call option and resource adequacy (RA) capacity.

The 13 MW annual baseload contract, heat rate call option and resource adequacy contracts covered the period 2009 through November 2013. The seasonal baseload contract, supplying 5 MW in November and 7 MW in December, January and February, covered 2009 through December 31, 2011.

To replace the above contracts, BVES issued two separate competitive Requests for Proposals (RFP), one for annual and seasonal baseload and a physical call option and the other for system RA. After a thorough evaluation of the bids, BVES awarded the annual baseload and physical call option contracts to EDF Trading North America, LLC (EDF) while Shell was awarded the contracts for seasonal baseload and the system RA.

2.F.2 Current Energy Contracts

In December 2014, BVES received the Commission approval of the power purchase agreements resulting from the RFPs. The contracts for the annual and seasonal baseload and physical call option began delivering power January 1, 2015 while the RA contract commenced in March 2015. EDF is the provider of the annual baseload and physical call option products, while Shell is the provider of the seasonal baseload and RA. The contracts' attributes are shown in Table 13.

Table 13: Current Energy Contracts

Product *	Resource Type	Term Years	Capacity (MW)	Time Dimensions (hours/day, days/week)
Annual Baseload	CAISO Firm Energy	4 yrs, 11 mo	12 MW	24/7 All months
Seasonal Baseload	CAISO Firm Energy	3 yrs	5 MW Nov 7 MW Dec-Feb	24/7 All Months
Physical Call Option with $75/MWh Strike	CAISO Firm Energy	3 years	7 MW winter; 3 MW other	16/7 All Months
System Resource Adequacy Capacity	Gas Turbine; Combined Cycle Combustion Turbine	4 yrs, 11 mo	15 - 31 MW ** depending on month	24/7 All Months

* For all products, delivery point is SP15 EZ Gen Hub in CAISO, as defined in the EEI Master Power Purchase and Sale Agreement, as amended.
** MW capacity in RA product refers to the combined amount of RA that BVES will purchase.

Because the Commission approval of the Shell and EDF contracts did not occur before the November 2013 expiration of the previous Shell contract, BVES purchased its annual and seasonal baseload and RA requirements on a monthly basis by issuing Requests for Offers (RFO) to various energy supply firms.[17] The resulting monthly transactions were governed by the Western Systems Power Pool (WSPP) Agreement in effect at the time of the transactions.[18] The amount of firm energy and capacity (RA) BVES purchased on a monthly basis matched the volumes in the contracts that the CPUC approved in December 2014.

2.F.3 Bear Valley Power Plant (BVPP)

The BVPP became commercially operational on January 1, 2005. The current Permits to Operate (PTOs), issued on March 26, 2009 in compliance with current air district rules, limit each engine to 1,000 hours of operation annually.[19]

The BVPP is currently treated as a distributed generation, or "behind-the-meter" resource, by the CAISO and is not under a Participating Generator Agreement (PGA). When operating, the BVPP reduces BVES' metered peak demand on the CAISO system, as measured by the SCE meters at the Goldhill receipt point.[20] Operation of the

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[17] As noted, the seasonal baseload product expired December 2011.
[18] BVES is a member of the WSPP.
[19] The 1,000 hours per engine annual limitation does not include hours BVPP operates due to loss of a transmission line. The limit can be increased by application to the South Coast Air Quality Management District (which may take up to one year to process) and under current air district rules, would require additional CEMS equipment to continuously monitor CO.
[20] Operating the BVPP does not affect SCE's metering at the Harnish receipt point.

BVPP can be very useful during on-peak periods when power costs may be higher than the marginal cost of operating the BVPP. Although there are maintenance costs such as running the BVPP for inspections and maintenance, these costs are not factored into the decision to run the plant based on economics. Only the marginal costs are considered in the economic evaluation of resource deployment.

BVES is able to reduce energy costs and increase price certainty by contracting for as much energy as possible from high capacity factor (baseload) resources and then meeting additional peaking and intermediate load through the CAISO Day Ahead (DA) market or the BVPP. If energy prices in the DA market are forecasted to be less than the cost of production from the BVPP, BVES does not operate the BVPP and instead purchases energy in the DA market. Otherwise, the BVPP could be utilized to satisfy demand. Operating in this fashion allows BVES to avoid paying capacity costs for a low capacity factor resource and also helps BVES reduce its contribution to system peaks.

2.G Procurement Plan

BVES analyzed the benefit of renewing existing contracts for annual and seasonal baseload and a physical call option(s) at the current contract volumes once the contracts expire. The total annual savings from renewing current contracts is potentially significant. Other options include maintaining the current annual baseload volume, extending the existing seasonal baseload and physical call option contracts but with different volumes and differentiating on and off peak load. Another option was to use shaped annual and seasonal contracts to hedge the volumes over the next 3 years. The contract volume would vary by hour across the months. This approach was selected as the optimal procurement strategy because it yields the highest savings and it maintains a minimal imbalance between demand and supply in daily transactions.

BVES also considered extending contracts beyond 59 months by tying contracts to specific assets with the goal of reducing contract prices as fuel producers try to hedge their production returns. Given the uncertainty in the gas market as shale plays mature, greater efficiency in production and drops in LNG prices, many buyers and producers wonder how low gas prices will go. As a result, this may be the best time to lock into contracts longer than 59 months at prices similar to the price bids for the contracts received from the existing suppliers of the energy products. The element of risk may incentivize suppliers to price product below the benchmark prices. Although BVES will pursue 59-month contracts to minimize the risk, there are benefits for “extended range” products that indicate savings would be multiples of the savings generated from the 59-month contracts. Only a few very large utilities have pursued these extended term contracts.

BVES’s proposal to purchase an 8 MW Single Axis tracking solar facility on 60 acres of land at Baldwin Lake (BBARWA) offers an excellent alternative to the contracts tied to specific assets and offers a long term hedge on pricing, RA, RECS, a daytime capacity increase, and a means of reducing emissions for Southern California. This option uses land which has no other commercial value to BVES service area. With a 5

MW battery solution, this asset offers all of the above, plus a night time capacity increase. The capacity increase benefit to BVES customers is the avoided interruption of sales to the A5 Primary customers which increases revenues and reduces the average fixed cost for all customers. The 30% Federal Investment Tax Credit available for the solar and battery solution makes this proposal even more cost effective for customers.

BVES will pursue other local supply options and storage solutions as a hedge for supply cost, an instrument for increasing capacity, and a means of reducing carbon emissions as land becomes more available. For the current IRP outlook, the Purchase Power Contacts for Firm power will be pursued by BVES to supply power through 2024, given the purchase of the 8 MW solar project and a 5 MW/4 hour battery solution.

BVES developed a benchmark pricing methodology to facilitate approvals by the CPUC for BVES power contracts. This is a policy tool that provides pre-approved benchmark prices. If prices in the bids are below the benchmark prices, the product purchased by the utility would be reviewed by the Commission via an Advice Letter filing.

In the analysis for determining the benefits of contract volumes and renewals, BVES discounted the benchmark price based on experience on bidding in the latest procurement cycle. The discounted price was then applied to analysis as the contract price. Note that the benefit analysis assumed proposed capital projects, rate programs, and supplemental sales occur concurrently with the renewed contracts, with the higher volumes for the annual baseload and existing volumes for the renewal of the other products. It was determined that the contract renewal and the capital projects and rate design initiatives complement each other; in other words, the initiatives and the procurement plan benefit as a whole do not diminish the individual initiatives values.

The contracts, existing and proposed, are listed in Table 14. Note that the evaluation end date is December 2028, even though contracts would extend beyond 2028.

Table 14: Existing and Proposed Contracts for BVES

Contract	Hours	Capacity	Duration
Annual Base Load Fixed Price (Existing)	7*24 Hours, All Months	12 MW	Jan 2015 – Nov 2019
Annual Base Load Fixed Price (New, option 1)	7*24 Hours, All Months	16 MW	Dec 2019 – Oct 2024
Annual Base Load Fixed Price (New, option 2)	7*24 Hours, All Months	Shaped: 14,14,,13,13,13,13,13,11,11,10,9,12, 12,13,14,12,15,17,18,16,16,15,13,15	Dec 2019 – Oct 2024
Annual Base Load Fixed Price (New, option 1)	7*24 Hours, All Months	16 MW	Nov 2024 – Sep 2029
Annual Base Load Fixed Price (New, option 2)	7*24 Hours, All Months	Shaped: 14,14,,13,13,13,13,13,11,11,10,9,12, 12,13,14,12,15,17,18,16,16,15,13,15	Nov 2024 – Sep 2029
Seasonal Base Load (Existing)	7*24 Hours, Nov	5 MW, 7MW	Jan 2015 – Dec 2017
Seasonal Base Load (New, option 1)	7*24 Hours, Nov, Dec-Feb	21 MW	Jan 2019 – Dec-2022
Seasonal Base Load (New, option 2)	7*24 Hours, Jan ,Feb ,Nov ,Dec	2019: 25,20,27,23 MW 2020: 23 MW 2021: 23 MW 2022: 23 MW	Jan 2019 – Dec-2022
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Jan 24,25,25,26,26,26,26,27,28,27,25,22 ,21,21,20,21,24,21,20,22,22,23,25,23	Jan 2019-Dec 2022
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Feb 22,22,22,23,25,26,26,27,22,20,19,18, 18,15,15,15,13,14,16,17,20,20,22,23	Jan 2019-Dec 2022
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Nov 20,20,22,22,23,23,24,24,22,18,18,15, 14,13,14,15,16,16,15,16,16,16,18,20	Jan 2019-Dec 2022
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Dec 24,25,25,26,26,26,26,27,25,24,23,22 ,21,21,22,23,24,21,20,22,22,23,25,23	Jan 2019-Dec 2022
Seasonal Base Load (New, option 1)	7*24 Hours, Nov, Dec-Feb	21 MW	Jan 2023 – Dec-2026
Seasonal Base Load (New, option 2)	7*24 Hours, Jan ,Feb ,Nov ,Dec	2019: 25,20,27,23 MW 2020: 23 MW 2021: 23 MW 2022: 23 MW	Jan 2023 – Dec-2026
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Jan 24,25,25,26,26,26,26,27,28,27,25,22 ,21,21,20,21,24,21,20,22,22,23,25,23	Jan 2023-Dec 2026

Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Feb 22,22,22,23,25,26,26,27,22,20,19,18, 18,15,15,15,13,14,16,17,20,20,22,23	Jan 2023-Dec 2026
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Nov 20,20,22,22,23,23,24,24,22,18,18,15, 14,13,14,15,16,16,15,16,16,16,18,20	Jan 2023-Dec 2026
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Dec 24,25,25,26,26,26,26,27,25,24,23,22 ,21,21,22,23,24,21,20,22,22,23,25,23	Jan 2023-Dec 2026
Seasonal Base Load (New, option 1)	7*24 Hours, Nov, Dec-Feb	21 MW	Jan 2027 – Dec-2030
Seasonal Base Load (New, option 2)	7*24 Hours, Jan ,Feb ,Nov ,Dec	2019: 25,20,27,23 MW 2020: 23 MW 2021: 23 MW 2022: 23 MW	Jan 2027 – Dec-2030
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Jan 24,25,25,26,26,26,26,27,28,27,25,22 ,21,21,20,21,24,21,20,22,22,23,25,23	Jan 2027-Dec 2030
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Feb 22,22,22,23,25,26,26,27,22,20,19,18, 18,15,15,15,13,14,16,17,20,20,22,23	Jan 2027-Dec 2030
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Nov 20,20,22,22,23,23,24,24,22,18,18,15, 14,13,14,15,16,16,15,16,16,16,18,20	Jan 2027-Dec 2030
Seasonal Base Load (New, option 3)	7*24 Hours, All Months	Shaped: Dec 24,25,25,26,26,26,26,27,25,24,23,22 ,21,21,22,23,24,21,20,22,22,23,25,23	Jan 2027-Dec 2030

2.H Summary and Conclusions

An updated analysis of BVES' load for this IRP suggests that the current economic conditions and other factors will maintain BVES' loads despite the residential and commercial solar production and the increases in efficiency impact. The BBARWA and Snow Summit supplemental sales will step up load significantly. The U.S. economy has grown moderately through 2018. Growth factors include near low price environment for natural gas and oil, low prices for commodities in general created by the Tax Cut and Jobs Act in 2017, infrastructure expansions across the country creating job increases, housing recovery, consumer debt reduction, and pent up consumer demand. In addition to macroeconomic growth, the California region will outpace the US economy because of strong population growth, a younger population, an average education level of the labor force, the attraction of milder weather and geographic wonders, a robust growth in housing construction, and the availability of venture capital. BVES regional economic activity growth is driven by expansion in the entertainment and real estate markets for Los Angeles, economic development which attracts new industry into the area. Potential demand from electric vehicles will be studied with the approval of the transportation electrification pilot project which will support connection of charging stations to the grid and create a Time of Use incentive rate for car charging.

This IRP represents a conservative assessment of load growth. If Distributed Generation does not grow as robustly as anticipated, BVES firm load would grow anywhere between a slight growth rate to moderate growth rate. BVES will continue to monitor the continued adoption of customer Distributed Generation and moderate its forecasts accordingly.

The two uncertainties for load growth are the Snow Summit and the BBARWA expansions. The load profiles and the amount of retail sales are estimated based on discussions with the two customers and review of the historic usage patterns. BVES used the usage patterns of the Bear Mountain snow making load from 2004 to 2017 to determine likely patterns for snow making for the new supplemental load from Snow Summit ski resort, currently served by Snow Summit's in-house diesel generated power. BBARWA has supplied all of their load through their in-house gas fired generation since 2004. BVES proposal for supplemental sales to BBARWA will be tied to an incentive rate for BBARWA in exchange for use of 60 acres of land for the 8 MW Solar project. The supplemental load that BVES will serve from BBARWA was estimated based on the usage patterns established in 2000 to 2002 when all of the load was served by BVES. BVES is assuming all of the load will return as confirmed by BBARWA. The magnitude of the increase in sales from these two customers could be as high as 20,000 MWh in 2020 out of 135,000 MWh total retail sales without the supplemental sales. This is a 14.8 % increase in BVES sales in 2020 created by these supplemental sales. This has a significant influence on the contract hedging plan for 2020 to 2028. This will also benefit all customers as the incremental sales will contribute revenues towards fixed capital and contract costs; thereby reducing future rates for all customers. Although these expansions are highly likely to occur, there are still contracts pending and CPUC approval required before these sales come to fruition.

Another uncertainty is the 8.0 MW BVES Solar project on BBARWA property. This solar project will provide local supply of power and will save on transmission, Resource Adequacy, Renewable Energy Credits expenses, and reduce carbon emissions for Southern California. This project will also reduce interruptions on supply to Snow Summit for snow making and will therefore increase retail sales for BVES. The result of these impacts will be reduced cost of supply for BVES customers. This project is highly likely but it is pending contract and CPUC approval.

Another uncertainly is the 5 MW battery storage project, optimized for 4 hour discharge capability. This would provide supply cost savings; reduce Resource Adequacy requirements, and reduce transmission capacity charges through load shaping. The battery can also provide voltage support. If BVES co-commissions this facility with the BVES solar project, there would be 26% to 30% Investment Tax Credit. All of these factors reduce the cost of supply for customers. The charge and discharge of the battery would increase the daytime load and decrease the nighttime load. The IRP assumes the battery will be in operation by 2020. The battery duty cycle will shift 14,600 MWh a year, which is 9.4% of retail sales in 2020. This project is still pending BVES executive approval and CPUC approval. Although not certain, this project is likely to occur given the wide load swings in the BVES load and the fact that in a tourist community, the battery offers the best solution to load management.

Capacity constraints limit total peak load for the non-firm customer class; but even in extreme weather scenarios where capacity limits are approached, the duration of the peak load(s) is very short-lived. Options for managing peak loads effectively include Demand Side Management programs such as interruptible tariff schedules, time-of-use rates, and water heater and spa cycling. These measures can shift load usage by a few hours and even minutes to achieve the resource balance needed during peak hours. Because of the fact that most residential and commercial activity is driven by visitors to Bear Valley Electric Service area who are not permeant residents of BVES service area; BVES is pursuing the energy storage applications to meet peak load requirements or a combination thereof. Solar production in the daytime with energy storage solution can provide the capacity constraint relief to the service area.

Still, BVES' annual retail sales remain below the all-time sales achieved in 2006. Energy sales declined in 2007 and continued to decline significantly through 2010. While the national economic recession was partially the cause, the decline in real estate values had a major effect on the growth of the Big Bear economy and local activity. With the recovery in the economy and real estate more pronounced in 2012 and continuing through 2015, BVES sales have increased from the 2010 levels. In 2015, BVES sales were 2.0% short of the peak sales in 2006 while 10.3% higher than the low point set in 2010. From 2016 to 2017, milder weather, efficiency, a lower amount of snow making in 2016 compared to 2015, and a significant increase in solar production from BVES customers have displaced enough sales to result in a downturn in total retail sales.

There is still a significant amount of commercial and residential developed property available for occupation to accommodate growth in residential and commercial activity driven from growth in demand from the Los Angeles economy. Until underutilized rental property and commercial real estate is absorbed by the local economy, there will always be an attraction to investment in BVES' service area. The high cost of real estate in California has attracted real estate investment away from the coastal areas towards the Inland Empire. This will also boost investment into the BVES service area.

Although there will be downward pressure on wholesale power prices in Southern California, prices for SP15 are expected to increase moderately due to a variety of reasons, including economic growth in California, the 50% RPS requirement for energy resources by 2030, the carbon allowance pressures in the WECC region on electric prices, the eventual recovery of the world market stimulating growth in oil and gas prices, and challenges from managing the influx of intermittent resources. A review of the forward market prices relative to the spot market forecasts provided by IHS-CERA indicate that fixed price contracts may likely be bid at a price significantly discounted from the forward spot market view provided by IHS-CERA. All of the above indicators were considered in the testing of the benefits of fixed price contracts. The conclusion from the resource planning analysis indicates that BVES should continue to hedge a significant portion of energy requirements price through fixed price contracts.

BVES' current energy contracts stem from power purchase agreements approved by the CPUC in December 2014. The contracts for the annual and seasonal baseload and physical call option began delivering power January 1, 2015 while the RA contract commenced in March 2015. EDF is the provider of the annual baseload and physical call option products, while Shell is the provider of the seasonal baseload and RA. At this point the seasonal firm power contracts and the call options have expired. The contracts remaining are the annual contract to expire November 2019 and the RA contract to expire in January, 2020.

Planning for contract renewals, BVES has solicited bids for seasonal and annual firm purchase power. The volumes were changed from the previous and existing contracts because of the planned supplemental sales to BBARWA and Snow Summit, the 8 MW single axis tracker facility, and the 5 MW battery storage with a 4 hour duration. BVES requested annual firm contracts which remain fixed for the duration of the contract and which vary across the years. BVES also requested shaped contracts which vary in volume by hour, but remain fixed within the months. The annual contracts would be for 59 months and the seasonal contract would be for 36 months. BVES received eight bids from energy suppliers. BVES is in the process of selecting finalists for the products and will be filing with the CPUC on the seasonal and annual firm energy contracts. BVES intends to solicit requests for bids for a reduced volume of Resource Adequacy for 59 months in 2020. The reduced volumes in the request for proposals are the result of the planned 8 MW Solar and 5 MW battery solutions in 2020. The call options will not be pursued as the firm contracts with the battery solution would provide a more effective solution for hedging the price risk for projected hourly loads.

3. Renewable Resources

3.A Background of the Renewable Portfolio Standard (RPS)

Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2, California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.

In January 2015, Governor Brown called on lawmakers to increase the RPS target to 50% by 2030 and in October 2015 he signed into law Senate Bill 350. SB 350 increases the RPS requirement to 50% by 2030 and also requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions to 1990 levels by 2020 and to 40 percent of 1990 levels by 2030, doubling energy efficiency, and promoting transportation electrification.

3.B. BVES and the RPS

In late 2011, D.11-12-052 defined and implemented portfolio content categories ("PCCs"). Most retail sellers subject to the RPS must procure certain quantities from each of the PCCs. The PCCs, in brief summary, consist of:

1. Generation facilities that have their first point of interconnection to the Western Electricity Coordinating Council transmission grid within the metered boundaries of a California balancing authority area (PCC 1);[21]
2. Generation from a facility that is firmed and shaped with substitute electricity scheduled into a California balancing authority within the same calendar year as the generation from the facility eligible for the California renewables portfolio standard, and that the substitute electricity provides incremental electricity (PCC 2); and
3. Other products like unbundled RECs that do not apply to the first two categories (PCC 3).

Of importance, D.11-12-052 confirmed that BVES may satisfy its RPS obligations without regard to the PCC limitations to which other retail sellers must adhere. Since BVES is exempt from following the product content categories, it intends to comply with the majority of its RPS requirements with unbundled RECs (i.e. PCC 3), which is the least expensive option of the RPS-eligible products.

In June 2012, BVES issued an RFP for RECs that sought pre-2011 volumes in addition to its then-current and future compliance period needs. After identifying a successful

[21] Procurement claims from contract/ownership agreements executed before June 1, 2010, or January 13, 2011 for ESPs, are not subject to the PCC classifications established in D.11-12-052. For the purposes of RPS compliance, any eligible RPS RECs that are not subject to PCC 1, 2, or 3 will be placed in their own classification, referred to as PCC 0.

bidder, BVES began negotiations for a long-term contract for unbundled RECs. In February 2013, GSWC on behalf of BVES filed Advice Letter 277-E with respect to its ten-year RPS agreement for the purchase of RECs from Iberdrola Renewables, LLC (now called "Avangrid Renewables, LLC, or "Avangrid"). CPUC Resolution E-4604, issued in July 2013, approved the ten year contract. The volumes in the ten-year REC contract were originally forecasted to fulfill all of BVES' RPS obligations through 2023.[22] The updated retail sales forecast now projects full RPS compliance through 2021 , without BVES 8 MW solar facility, and through 2023 with the BVES solar facility output . See Table 15 for more details on contract volumes, RPS obligations, and forecasted length and shortfalls.

Table 15: BVES RPS Position Using 2018 IRP Sales Forecast

RPS Position Using 2018 IRP Sales Forecast -- 50% by 2030

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Retail Sales	133,873	130,299	135,730	144,741	155,605	154,257	153,317	152,861	152,953	152,626	152,108	151,640	151,189
RPS %	25.00%	27.00%	29.00%	31.00%	**33.00%**	**34.40%**	**35.80%**	**37.20%**	**40.00%**	**41.67%**	**43.33%**	**45.00%**	**46.67%**
BVES' RPS Obligation	33,468	35,181	39,362	44,870	51,350	53,065	54,887	56,864	61,181	63,594	65,913	68,238	70,555
Annual RECs (Base + Option RECs)	38,865	42,425	45,444	48,455	51,661	51,640	51,594	51,617	-	-	-	-	-
Length/(Shortfall)	5,397	7,244	6,082	3,585	311	(1,425)	(3,293)	(5,247)	(61,181)	(63,594)	(65,913)	(68,238)	(70,555)
Solar Facility Production					19,769	19,631	19,493	19,357	19,221	19,087	18,953	18,820	18,689
Length/(Shortfall)					20,080	18,206	16,200	14,110	(41,960)	(44,507)	(46,960)	(49,418)	(51,866)

Note:
The REC volumes in the contract with Avangrid were based on the 33% by 2020 RPS law. This table shows the annual RPS% increments proposed by the CPUC under the new 50% by 2030 law.
Solar facility production can offset RECS one for one.

As previously discussed**,** BVES is planning to develop a 8 MW (DC) solar generation facility at the Baldwin Lake land owned by BBARWA and within the BVES territory. The 8 MW (AC) facility should produce approximately 19,769 MWh per year of RPS-eligible energy the first year with a 0.7% annual degradation rate over the next 25 years. Even with this solar generation project, BVES will likely still need to purchase additional RECs or other RPS-eligible products if forecasted sales come to fruition. Procurement targets for the intervening years within a compliance period are not enforceable; rather, the targets determine the overall procurement requirement for that compliance period. As such, BVES must acquire and retire a sufficient amount of RECs prior to the end of Compliance Period III, which is December 31, 2020, to remain RPS compliant and is confident it will do so.

4. Net Energy Metering (NEM)

4.A Background of Net Energy Metering (NEM) Legislation

In 1995, California was one of the first states to formally adopt net energy metering (net metering or NEM) for wind and solar systems. Simply stated, net metering allows

[22] Under the previous 33% by 2020 RPS, there were three compliance periods: 2011-2013, 2014-2016 and 2017-2020.Newly required increments to reach 50% by 2030 are used for the analysis through the Avangrid contract end date of 2023.

customers to use renewable resources (e.g., solar panels) to generate electricity and offset their consumption with their own power production. NEM is a tariff billing design that promotes the installation of onsite renewable generation by providing a bill credit for excess generation that is received by the electric grid when it is not serving onsite load. On a monthly basis, bill credits for excess generation are applied to a customer's bill at the full retail rate the customer would have paid for energy consumption. The full retail rate includes generation, distribution and transmission costs. At the end of a customer's 12-month billing period, any balance of surplus electricity is trued-up at a separate value called the net surplus compensation (NSC) rate, which is based on a 12-month rolling average of the wholesale market rate for electricity (approximately $.03-$.05 per kWh).

As noted above, a NEM customer is credited the full retail rate for excess energy put on BVES' distribution system. As a result of this state-mandated billing structure, BVES, like any utility that offers full-retail-rate NEM, does not collect the planned-for revenue needed to recoup its fixed and pass-through costs. While the NEM obligations of CPUC-regulated IOUs are capped at five percent of the utility's non-coincident peak demand across all customer segments, how the "missing" revenue is recovered has created some level of controversy in the industry. Some believe that non-NEM customers essentially subsidize NEM customers while others believe utilities are simply clinging to an outdated business model.

To address the issues surrounding the future of NEM and to continue support for distributed renewable resources, the CPUC in July 2014 adopted Rulemaking (R.)14-07-00. The NEM 2.0 proceeding currently applies only to the large IOUs because they are already at or near their respective NEM caps.[23]

In January 2016, the CPUC issued Decision (D.) 16-01-044 that adopted a NEM successor tariff. While the CPUC describes the decision as making adjustments to align the costs of NEM successor customers more closely with those of non-NEM customers, many parties, including the Big Three IOUs in California, strongly disagree. In March of 2016, the Big Three simultaneously requested that the CPUC vacate or modify their decision. The main issue for opponents of the January decision is the full retail rate credit provided to NEM customers unfairly penalizes customers without net metering. Non-NEM customers account for about 95% of all customers. BVES is not a party to the rulemaking but is monitoring it closely so that it can determine how to best navigate its NEM program. On October 12, 2016 BVES reached its NEM cap of 3.3 MW and filed an advice letter 325 E requesting permission from the CPUC to close the NEM. On November 30th, 2017, permission was granted by Edward Randolph, Director of Energy Division of the CPUC, for BVES to close the NEM. BVES has closed the NEM program as of January 1, 2018; however, did allow customers in the queue to complete NEM program installations until February 15, 2018. BVES is considering implementing a renewable DG tariff rate as its own "successor" tariff. The

[23] The California Solar Initiative, the rebate program upon which BVES' solar program was based and which was authorized only for the large IOUs, began in 2007. As a result, the large IOUs have or could meet the NEM cap sooner than BVES.

goal will be to achieve an equitable rate design for renewable DG customers customized to BVES rate design issues and meter technology capabilities.

BVES will continue to evaluate all costs and benefits of net metering and may seek to revise rates for future customers entering the program.

4.B Impact of Net Energy Metering (NEM) on BVES Sales

As of February 21, 2018, BVES has 445 customers on the NEM rate (24 commercial and 428 residential). Installed capacity through this date was 3.4 MW, with a staggering 1.4 MW installed in 2015, 0.9 MW in 2016, and 0.5 MW in 2017. The vast majority of BVES NEM customers are solar. The significant spike in the number of interconnected solar installations can be attributed to a dramatic decrease in the price of solar panels and the January 2015 launch of the Bear Valley Solar Initiative (BVSI).[24]

NEM annual energy production has increased from an estimated 714,000 kWh in 2013 to 1,028,000 kWh in 2014 (a 44 % annual increase) to 2,255,344 kWh in 2015 (a 119% annual increase), 4,798,987 kWh in 2016 (115% annual increase), 6,056,180 kWh in 2017 (a 26% annual increase).

The largest risk to BVES retail sales growth and the biggest challenge to managing the system load requirement is the growth in net energy metering (NEM) customers. NEM and/or solar distributed generation (solar DG) annual energy production is projected to be 8,038,755 kWh in 2018, 9,528,610 kWh in 2019, 10,922,518 kWh in 2020, 12,329,949 kWh in 2021, and 13,604,072 kWh in 2022, reaching 15,756,186 kWh by 2024. This corresponds with solar DG capacity of 4.2 MW in 2018, 4.9 MW in 2019, 5.7 MW in 2020, 6.4 MW in 2021, and 7.1 MW in 2022, reaching 8.2 MW by 2024. The historic growth is driven by the savings opportunity that exists under the current Net Metering Tariff versus the current BVES standard retail rates, the current 30% Federal Investment Tax Credit (ITC) for residential and commercial solar projects, and the reduced cost of solar installation. Future growth will be driven by the current 30% Federal Investment Tax Credit (ITC) for residential and commercial solar projects, and the reduced cost of solar installation, and the high retail rates at BVES. The current production forecast reflects BVES NEM customers achieving 33% of the potential load by 2024, of all customers who could achieve full payback of the solar production investment within 5 years or less.

A review of all the accounts of the residential and commercial customers who are not on the Net Metering program – what they pay currently versus what they would pay under the net metering program – yields the estimated savings and the payback period for each individual customer were they to install a solar PV system in their home under the current NEM rates. The total kWh energy consumption of potential Net Metering

[24] The Bear Valley Solar Initiative (BVSI) is a CPUC-approved program that pays rebates to residential customers who install qualified solar systems. The BVSI applies only to residential customers, though any customer class may install solar or wind under BVES' NEM tariff. 2015 installed capacity includes residential, commercial, government and school installations.

customers with a payback less than 5 years was 46,139,277 kWh per year. It is very likely that up to 33% of the potential Net Metering Customers (Distributed Generation Renewables) could decide to install a solar system and subscribe to the Distributed Generation Renewables program, and displace up to 15,756,186 kWh of BVES annual sales by 2024. By 2028 Distributed Generation Renewables and Net Metering could displace up to 18,699,333 kWh of annual sales. See Figure 15 below.

Already the Bear Valley Solar Initiative program (BVSI), where BVES pays rebates for installed residential solar capacity to the customer, is completed as the CPUC-approved incentive funds have been exhausted. The popularity of solar distributed generation will continue. However, the future rate structure of distributed renewable generation given the legislatively mandated threshold of NEM subscriptions has reached 5% of the sum of non-coincident peak demand of all customer classes (3.3 MW based on 66 MW of combined non-coincident peak demand) will not likely include the full retail rate compensation under the current NEM rate for new distributed generation customers. All existing NEM customers will remain on existing NEM tariff for 20 years after they subscribed on the NEM tariff. A future solar or renewable DG tariff may better reflect the cost of service for solar generation customers and will ideally guarantee full recovery of these costs given the anticipated DG production profiles. This will avoid the non-NEM customers subsidizing the NEM customers, a more equitable option for future renewable DG.

Net Metering load has rapidly increased within the BVES service area, displacing retail sales. Analyzing the production capacity of NEM customers over time from a time series approach was not enough to fully capture the potential penetration of NEM production displacing retail sales. Times series analysis of the NEM customer capacity over time has underestimated the impact of NEM capacity enrollment. BVES also performed a payback period analysis of solar NEM program on all customers not participating in the Net Metering solar program in order to determine those customers most likely to strongly consider solar net metering (those with a payback of less than 5 years). Taken into account were the current underlying retail rates, the current NEM rate structure), the Federal ITC program, the cost of solar panel installation, and individual usage patterns of the customers. This set the potential for maximum enrollment into the NEM program. Also a time series analysis of the capacity enrollment of the NEM customers resulted in an alternative NEM enrollment forecast. The high NEM enrollment case has annual solar energy production amount equal to 1/3 of the potential NEM customer amount by 2024. A forecast of hourly load for NEM customers (displaced retail sales load) was applied to the electric consumption forecast to derive the retail sales forecast. Alternative forecasts of NEM production was used to derive the alternative forecasts for retail sales.

Although BVES uses the conservative forecast with a high penetration of Net Metering/DG production in the BVES supply mix (15,756,186 KWh by 2024), other scenarios were considered for planning purposes. These include a higher penetration of solar generation capacity given a lower cost of panels (Autonomous Scenario) and a lower penetration of solar generation capacity given a higher cost of panels (Vertigo Scenario). See figure 16 below. BVES used each of these three forecast scenarios as input into the retail sales forecast analysis.

Figure 15: Residential and Commercial Customer Owned Solar Generation Capacity and Production

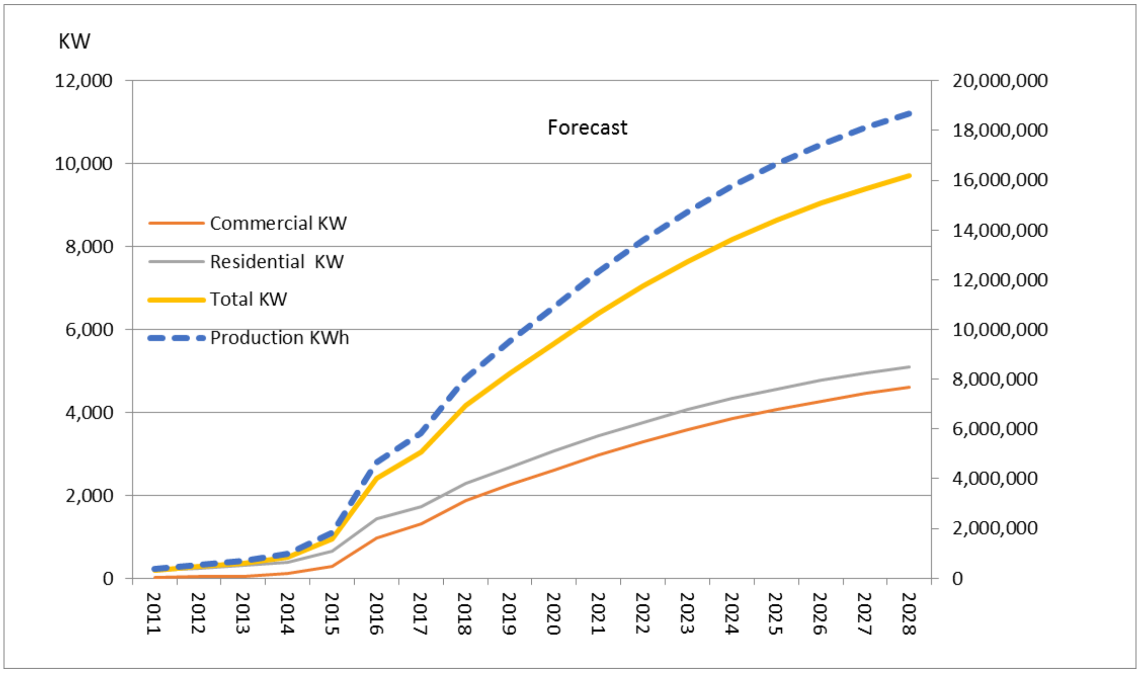
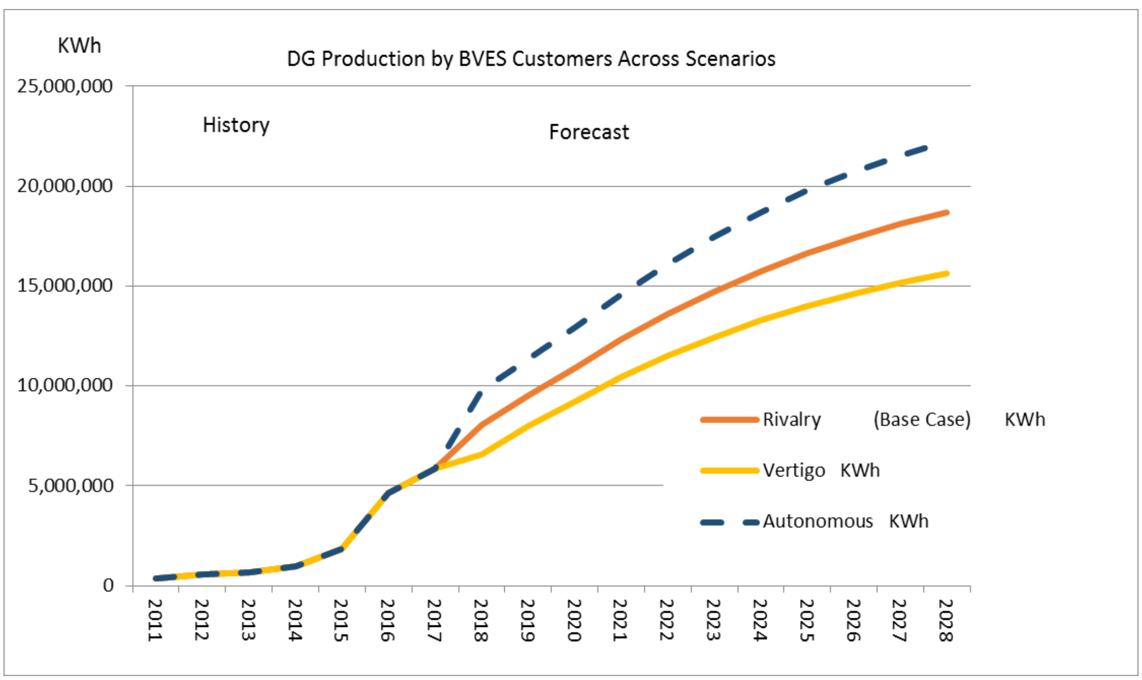


Figure 16: Residential and Commercial Customer Owned Solar Production by Scenario



5. Other Factors Affecting Resource Procurement

5.A CAISO Wholesale Market

The CAISO's Market Redesign and Technology Upgrade (MRTU) Tariff has been in operation since April 1, 2009. From BVES' perspective, it appears that the market has performed as intended. Given that MRTU enacted a complete overhaul of California's system of wholesale power delivery as a result of the California energy crisis in 2001, it has required occasional fine-tuning, as originally communicated to market participants by the CAISO.

To monitor the efficiency and effectiveness of ancillary services, congestion management and real-time (RT) spot markets, the CAISO maintains a Department of Market Monitoring (DMM). Another key charge of the DMM is to ensure that no participant can take unfair advantage of the rules or procedures or concentrate market power and inhibit competition. Once per year, the DMM publishes its "Annual Report on Market Issues and Performance" (Annual Report).[25] Section 5.A discusses the key points relevant to BVES contained in the 2017 Annual Report.

Key Items in the 2017 Report

See figure 17. The market prices rose over the 2016 to 2017 period. Congestion, Resource Adequacy flex capacity failures, and Aliso Canyon and gas transmission disruptions contributed to the price spikes and higher average prices. Hedging of BVES system energy requirements for BVES is crucial during the forecast years from 2018 to 2028.

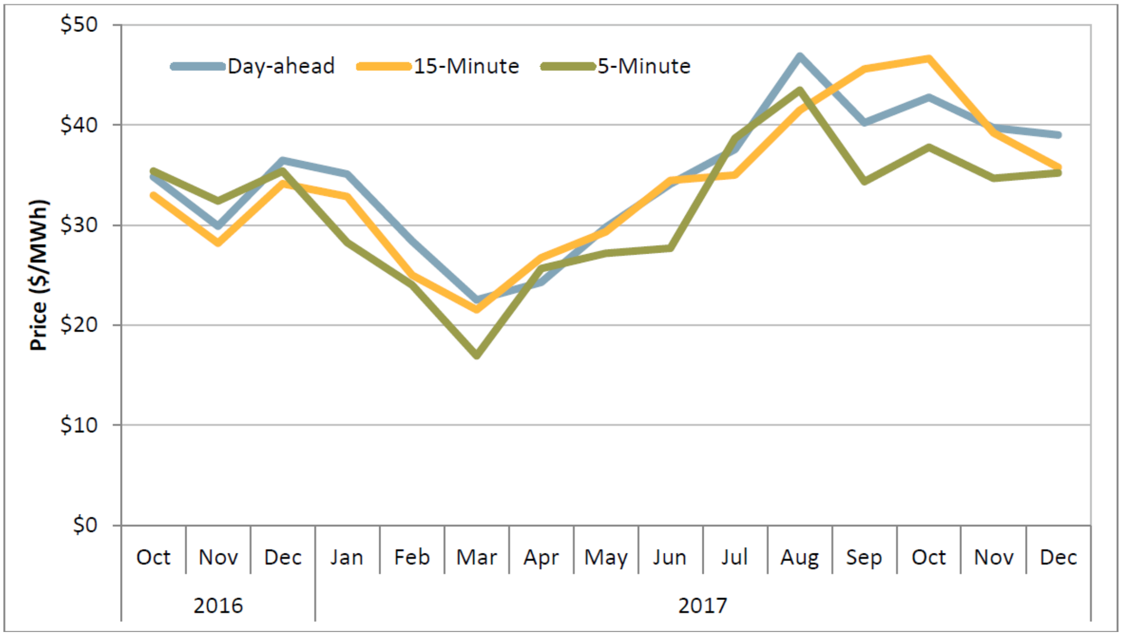
- Average 15-minute system market prices continued to increase in October to almost $47/MWh, but then decreased in November and December. In October, average 15-minute market prices were higher than day-ahead and 5-minute market prices by about $4/MWh and $9/MWh, respectively. Prices in the 15-minute market were above $750/MWh during almost 1 percent of intervals in October.
- High 15-minute prices during October were concentrated between hours ending 18 and 20, when net load was highest. Many of these high prices occurred in intervals when the supply of ramping capability bid into the market was fully utilized and the power balance constraint was relaxed. Even when the load bias limiter was triggered, prices were often set by bids greater than $900/MWh.
- During the fourth quarter of 2017, auction revenues for congestion revenue rights were $61 million less than congestion payments made to non-load-serving entities purchasing these rights. This increased the total 2017 ratepayer losses in the congestion revenue rights auction to about $101 million. Losses in

[25] For the full text of the Annual Report, see http://www.caiso.com/Documents/2017AnnualReport_MarketIssues_Performance.pdf

the fourth quarter represent $0.25 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders.

- In the fourth quarter, gas price adders used in calculating bid caps for units in the areas affected by Aliso Canyon gas storage limitations were active in the market for a few days in October and almost the entire month of December. DMM estimates that activation of the gas price adders in 2017 resulted in over $5 million in additional uplift payments to resources using these adders. Approximately $1 million of these payments was accrued in December during Southern California wildfires.
- Portland General Electric became a participant in the energy imbalance market on October 1. Prices in Portland General Electric were often lower than prices in the ISO because of limited transmission from PacifiCorp West and Portland General Electric to the ISO.
- The ISO made annual capacity procurement designations for 2018 in response to sub-area deficiencies in the resource adequacy showings of load-serving entities. Designations were made for three resources for more than 500 MW of capacity in the San Diego Gas and Electric area and more than 500 MW of capacity in the Pacific Gas and Electric area. Estimated costs for these designations are about $80 million. The ISO also procured the Metcalf resource (593 MW) through a reliability must-run procurement for 2018. This resource has a fixed revenue requirement of about $72 million.
- There was significant north-to-south congestion in the day-ahead market during the quarter, primarily the result of planned outages in Southern California. This congestion increased day-ahead prices in Southern California by about $2/MWh and decreased prices in Northern California by about the same amount.
- Outages in Southern California also caused congestion in the 15-minute market. Congestion increased prices in the San Diego Gas and Electric area by about $4/MWh and in the Southern California Edison area by about $3/MWh, but had little impact on Pacific Gas and Electric area prices.
- Total payments to generators for flexible ramping capacity decreased during the fourth quarter to about $3 million, compared to about $5 million during the previous quarter. This is the lowest amount of quarterly payment since the flexible ramping product was implemented in 2016. This was in part driven by adequate system availability in most intervals resulting in $0/MWh prices.
- Prices in PacifiCorp East, NV Energy and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas, particularly during hours ending 17 through 21. This was often the result when one or more of these areas failed their flexible ramping sufficiency test or an area’s export limits bound when prices in the surrounding balancing areas were high.
- Balancing areas failed the flexible ramping sufficiency test relatively infrequently during the fourth quarter, during less than 3 percent of hours, for each area and direction. NV Energy failed the upward sufficiency test less frequently during only about 2 percent of hours during the quarter, compared to about 5 percent of hours in the previous quarter.

Figure 17: CAISO Market Price Performance 2016 and 2017



5.B Resource Adequacy

The CPUC adopted a Resource Adequacy (RA) policy framework in 2004. In June 2013, the CPUC modified the RA program by adoption of a flexible capacity requirement. Each LSE will now show flexible resources for each month of the compliance year.[26] The RA program works in conjunction with regulatory requirements and processes adopted by the CPUC, CAISO and other regulatory authorities. Section 40 of the CAISO Tariff further defines the RA program and standardizes the obligations placed on generation units used to meet resource adequacy requirements and facilitates bilateral contracting between load-serving entities and generators. The CAISO and the CPUC continue to work with stakeholders to standardize RA requirements for demand response programs.

5.B.1 Current State of RA Requirements for BVES

The purpose of the CPUC's Resource Adequacy program is to provide sufficient resources to the CAISO and appropriate incentives for new resources. In 2004, the CPUC adopted an RA policy framework (PU Code section 380) to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs). The CPUC has postponed a final decision on RAR requirements for BVES and other small and multi-jurisdictional utilities (SMJUs). The CPUC's decision D.10-06-018 on June 3, 2010 and R.11-10-023 again deferred this issue.[27]

Until such time as the CPUC provides a decision specifying RA requirements for BVES, BVES will continue to comply with the CAISO Tariff applicable to LSEs and submit its RA filings to the CAISO through its Schedule Coordinator. Substantively, BVES secures RA-eligible capacity under the CAISO Tariff that is similar to the CPUC RA program. BVES also complies with data requests from the California Energy Commission regarding load forecasts and historical loads consistent with the RA information requirements and processing applicable to the larger CPUC-jurisdictional entities.

In October 2014, the Commission opened R.14-10-010 to continue the CPUC's oversight of the program and consider refinements to the program. More recently, in late 2015, the Commission held a pre-hearing conference (PHC) to address the scope and schedule of the proceeding moving forward. It also indicated in the PHC announcement that the Commission was contemplating proposals on various topics, including RA obligations for small and multijurisdictional load serving entities. As such, BVES is closely monitoring the proceeding.

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[26] D.13-06-024, *Decision Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program*.

[27] D.10-06-018, page 3, states: "Track 3 of Phase 2 was established to address resource adequacy obligations for small and multi-jurisdictional load-serving entities that are not currently subject to the resource adequacy program. We find that it is appropriate to close this proceeding and resolve the Track 3 issues in a more appropriate proceeding." The new proceeding is R.11-10-023.

5.B.2 Background of BVES RA Proceedings

When the CAISO filed with FERC for approval of pre-MRTU tariff changes to implement the CPUC's RA program, BVES filed a protest at FERC to which the CAISO agreed that the CPUC had not yet established an RA program for BVES. FERC then ruled that the CAISO should treat all entities the same and should, therefore, impose an Interim Reliability Requirements Program (IRRP) for BVES under the CAISO tariff.[28] In a subsequent order, FERC provided a means to identify such a program until the CPUC developed an RA program for SMJUs.[29] The CPUC placed BVES issues in Phase II Track 3 of its 2009 RA proceeding, but that phase was ultimately deferred and the proceeding closed. The CPUC has delayed resolution in the current proceeding, R.11-10-023, and therefore BVES RA requirements will likely be postponed until further notice.

BVES complies with the FERC ruling and the CAISO Tariff by following these key provisions:

- BVES closely mirrors the State's monthly coincident peak demand calculation and provides the data to the CEC.[30]
- BVES treats the Bear Valley Power Plant (BVPP) as a distributed generation resource because the BVPP is not under a PGA and is behind the CAISO metering point. Such treatment effectively reduces BVES' monthly peak demand, thereby reducing BVES' capacity procurement obligation.

To comply with the current CAISO tariff, BVES follows a procurement obligation determination that is the functional equivalent to the program adopted by the CPUC for its jurisdictional LSEs. Beginning in early 2012, BVES began working with the CEC to count some of the BVPP capacity towards its RA obligation as a behind-the-meter resource. The CEC has calculated the BVES procurement obligation as presented by BVES, and the CAISO has accepted those values. Notwithstanding the absence of CPUC-specific RA program rules for BVES, BVES does not expect the CPUC to impose substantively different requirements should the CPUC ever adopt RA program elements particular to the company.

The current CAISO tariff applies default RA demonstration requirements on BVES through BVES' scheduling coordinator. BVES will continue to procure its obligation plus 15 percent reserve margin, as do other RA-obligated entities. The annual and monthly demand forecast submitted to CAISO for BVES will use the coincident-peak demand forecast calculated by the CEC. The CEC-calculated demand forecast, adjusted to account for the BVPP, is submitted to the CAISO for compliance purposes.

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[28] *California Independent System Operator Corp*, Order Accepting Tariff Revisions, as modified, FERC Docket ER06-723-000, 115 FERC ¶ 61,172 at P 48 (May 12, 2006).

[29] *California Independent System Operator Corp.,* Order on Rehearing, Clarification, and Compliance Filing, Docket No. ER06-723-001, *et al*., 118 FERC ¶ 61,045 at P 32 (Jan. 22, 2007).

[30] The CEC reviews this data and provides to BVES a procurement obligation value consistent with the treatment provided to other CPUC-jurisdictional LSEs.

To the extent that BVES is deficient in its capacity procurement, and the CAISO experiences an aggregate capacity shortfall for the same period, the CAISO would allocate backstop procurement to BVES in proportion to its shortfall. If there is no aggregate shortfall, CAISO would not undertake backstop procurement. In the unlikely event that the CAISO finds BVES' capacity procurement to be deficient, CAISO can inform the CPUC of BVES' deficiency which could be the subject of an enforcement action, although the basis for such enforcement action against BVES is not defined at this time.

Pending the adoption of a CPUC decision establishing RA requirements specific to BVES, and consistent with the current CAISO Tariff RA provisions, BVES is not subject to direct penalties for non-compliance with the RA procurement obligation. However, there are potential cost allocation mechanisms under the CAISO Tariff's CPM that apply to all LSEs.[31]

5.B.3 Calculation of RA for BVES

BVES has an RA procurement obligation that is established under the CAISO Tariff's default RA provision. The calculation of this obligation begins with BVES providing its previous year's historical annual load shape, year-ahead annual forecast, and BVPP output to the CEC who in turn issues to BVES its coincident peak demand level. Because BVES is a winter-peaking utility and has its summer peaks on holiday weekends, BVES' contribution to the CAISO system monthly coincident peak loads is insignificant because of the BVES system load timing diversity with CAISO.

For planning purposes, BVES assumes that its RA procurement obligations are as defined by the CAISO Tariff default provisions, which parallel the CPUC's program for jurisdictional LSEs; therefore, BVES plans for RA requirements equal to 115 percent of the CEC determined monthly coincident forecasted load. BVES has purchased RA capacity from Shell Energy North America as part of its long-term PPA to meet these RA obligations.

Listed in Table 16 is the total RA requirement calculated for BVES. This includes added the reserve margin requirement of 15% to the BVES peak demand coincident with the CAISO. BVES has been only able to acquire system RA for this total amount due to the lack of bid response on the flexible and local RA products. BVES will attempt again to aquire 3 RA products (Flexible, Local, and System) in the next bidding process for RA .

Table 17 is the flexible RA requirement for BVES. Table 18 is the local RA requirement for BVES. Table 19 is the System RA requirements .The three RA products (Flexible, Local, and System) sum to the total RA requirement, see table 16.

[31] Specifically, CAISO Tariff sections 40 and 43.

Table 16: BVES Total Resource Adequacy Requirement in MW: Includes Reserve Margin of 15%

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	33.11	30.97	26.10	26.18	32.59	33.96	33.96	33.96	33.96	33.96	33.96	33.96	33.96	33.96
2	23.23	41.58	26.06	24.96	30.99	35.65	35.65	35.65	35.65	35.65	35.65	35.65	35.65	35.65
3	25.61	23.59	22.14	19.31	23.07	33.24	33.09	32.97	32.92	32.96	34.92	35.99	35.96	25.14
4	21.25	24.05	21.51	18.57	18.49	19.38	19.21	19.08	21.55	19.00	21.89	19.20	19.14	19.08
5	19.02	23.97	18.76	18.87	17.58	16.21	16.03	15.92	16.97	15.93	18.04	16.66	16.61	16.57
6	19.69	20.28	19.69	21.48	21.09	19.32	19.12	18.98	22.04	18.95	22.37	23.52	23.46	23.42
7	22.59	28.84	27.68	20.80	22.13	20.17	19.98	19.87	22.62	19.88	24.29	25.11	25.07	25.04
8	19.92	26.85	25.32	21.87	21.16	19.70	19.55	19.46	24.24	19.44	22.70	23.75	23.71	23.65
9	21.10	23.67	22.15	21.38	21.23	17.69	17.51	17.40	19.59	17.42	21.24	23.07	23.02	22.97
10	21.82	21.81	22.68	21.17	19.23	26.43	26.28	26.19	26.78	26.19	29.53	31.01	30.95	30.88
11	20.22	29.54	25.17	20.90	28.11	27.90	27.71	27.61	29.70	27.57	29.95	29.95	29.95	29.90
12	37.32	31.72	26.55	28.81	31.72	31.72	31.72	31.72	31.72	31.72	31.72	31.72	31.72	31.72

Table 17: Flexible Resource Adequacy Requirement in MW

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1		6.59	7.58	5.44	6.94	7.23	7.23	7.23	7.23	7.23	7.23	7.23	7.23	7.23
2		4.42	8.90	8.11	10.07	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59
3		6.00	6.72	5.49	6.56	9.45	9.41	9.38	9.36	9.37	9.93	10.24	10.23	7.15
4		5.95	(2.29)	5.97	4.57	4.79	4.75	4.72	5.33	4.70	5.41	4.75	4.73	4.72
5		2.41	12.98	3.80	3.55	3.27	3.23	3.21	3.42	3.21	3.64	3.36	3.35	3.34
6		0.75	0.17	3.72	0.78	0.72	0.71	0.71	0.82	0.70	0.83	0.87	0.87	0.87
7		1.43	0.93	3.03	1.10	1.00	0.99	0.99	1.12	0.99	1.21	1.25	1.25	1.24
8		1.13	0.81	1.30	0.89	0.83	0.82	0.82	1.02	0.82	0.96	1.00	1.00	1.00
9		0.97	(2.04)	3.44	0.87	0.73	0.72	0.71	0.80	0.71	0.87	0.95	0.94	0.94
10		1.99	(1.27)	2.30	1.76	2.42	2.40	2.39	2.45	2.39	2.70	2.83	2.83	2.82
11		0.00	(0.29)	6.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12		8.03	1.20	13.53	8.03	8.03	8.03	8.03	8.03	8.03	8.03	8.03	8.03	8.03

Table 18: Local Resource Adequacy Requirement in MW

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
2		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
3		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
4		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
5		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
6		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
7		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
8		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
9		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
10		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
11		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96
12		12.05	12.05	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.96

Table 19: System Resource Adequacy Requirement in MW

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	33.11	12.32	6.47	11.78	16.69	17.77	17.77	17.77	17.77	17.77	17.77	17.77	17.77	17.77
2	23.23	25.11	5.11	7.89	11.96	15.10	15.10	15.10	15.10	15.10	15.10	15.10	15.10	15.10
3	25.61	5.54	3.37	4.86	7.55	14.82	14.72	14.63	14.60	14.62	16.03	16.80	16.77	9.03
4	21.25	6.05	11.75	3.65	4.96	5.63	5.50	5.40	7.26	5.34	7.51	5.49	5.44	5.40
5	19.02	9.51	(6.26)	6.10	5.08	3.98	3.84	3.75	4.59	3.76	5.44	4.34	4.30	4.27
6	19.69	7.48	7.47	8.80	11.34	9.64	9.45	9.32	12.26	9.29	12.58	13.68	13.63	13.59
7	22.59	15.35	14.70	8.81	12.07	10.21	10.03	9.92	12.53	9.93	14.12	14.90	14.86	14.84
8	19.92	13.67	12.46	11.61	11.31	9.91	9.77	9.68	14.26	9.66	12.79	13.79	13.75	13.70
9	21.10	10.65	12.14	8.98	11.40	8.01	7.83	7.73	9.82	7.75	11.41	13.16	13.12	13.07
10	21.82	7.77	11.90	9.91	8.51	15.06	14.92	14.84	15.38	14.83	17.87	19.22	19.16	19.10
11	20.22	17.49	13.41	5.22	19.15	18.94	18.75	18.65	20.74	18.61	20.99	20.99	20.99	20.94
12	37.32	11.64	13.30	6.32	14.73	14.73	14.73	14.73	14.73	14.73	14.73	14.73	14.73	14.73

In December 2011, BVES issued a Request for Proposals (RFP) for RA for the period December 2013 through December 2017. BVES received bids from four suppliers. The RA contract was awarded to Shell and began in March 2015 for a term of 59 months. In

March, 2020, BVES will have to acquire replacement RA products to continue RA coverage of the BVES load requirement.

5.B.4 Local RA Capacity

The CAISO will allocate responsibility for Local Capacity Area Resources to Scheduling Coordinators for Load Serving Entities and may procure Local Capacity if the CAISO determines there is a capacity deficiency within a Local Capacity Area. A deficiency in Local RA Capacity can occur because individual LSEs do not demonstrate sufficient procurement from local resources for twelve months in the Annual Resource Plans submissions or, notwithstanding sufficient compliance with LCR procurement obligation, because the CAISO determines a collective deficiency of local capacity in a LCA due to the effectiveness factors for the procured units. It should be noted that the CAISO does not consider the BVPP to be eligible as a Local Capacity Resource since it is not a participating generator in the CAISO system.

If required, the CAISO will make supplemental procurement for RA under the capacity procurement mechanism (CPM) provisions of its tariff described above. As detailed in the CAISO Tariff,[32] the CPM costs associated with the procurement of LCR will be allocated proportionately to all deficient LSEs within each Transmission Access Charge (TAC) Area, or in the case of a collective deficiency of local capacity, to all Scheduling Coordinators that serve load in the TAC Area. BVES' load is considered to be within the SCE TAC Area (LA Basin) by the CAISO.

The CAISO has determined that BVES' 2017 portion of the load within this area is 8.96 MW. Although BVES is not within any specific LCA,[33] the CAISO may allocate CPM cost to BVES because of local capacity shortages. BVES attempted to obtain a Local Capacity Resource in its latest RFP for RA (December 2011), but none of the proposals received included Local RA capacity. BVES will attempt to acquire local RA capacity by March 2020, when the system RA capacity product would have expired.

Table 20: BVES Local Resource Adequacy Requirement in MW

Load Serving Entity	CPUC or Non-CPUC	SCID	PGE TAC SHARE	SCE TAC SHARE	SDGE TAC SHARE	PG&E TAC Area Total (MW)	SCE TAC Area Total (MW)	San Diego TAC Area Total (MW)	Total Local Need by LSE (MW)
Bear Valley Electric Services	NON	APXG	0.00%	0.09%	0.00%	0.00	8.96	0.00	8.96

The current Shell contract offer provides System RA only; thus, BVES remains exposed to possible allocation of local reliability costs by the CAISO. To this end, BVES is evaluating this situation and may issue an additional RFP for a local SCE-area RA obligation.

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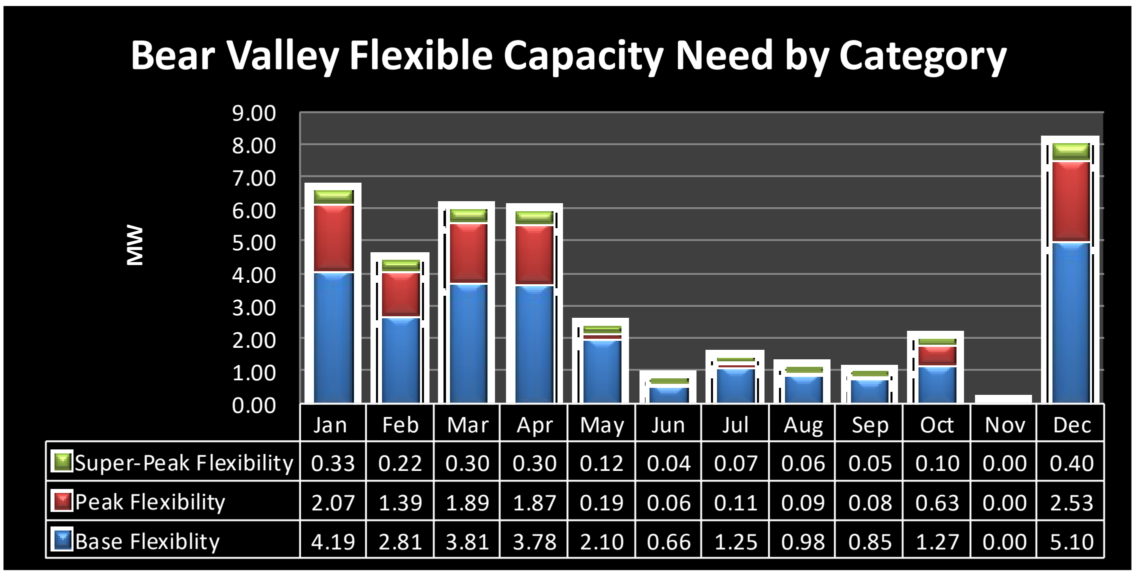
[32] CAISO Tariff Section 43, Capacity Procurement Mechanism.
[33] BVES load does not reside within the "LA Basin" or any other Local Capacity Area as defined in the CAISO 2015 Local Capacity Technical Study.

5.B.5 Flexible Resource Adequacy Capacity

Flexible capacity refers to resources that can ramp up and down, and start and stop quickly and multiple times per day. In June 2014, the CPUC issued a final decision to adopt firm flexible capacity obligations.[34] On August 1, 2014 the CAISO submitted tariff revisions with FERC to establish flexible capacity requirements.[35] FERC conditionally accepted the revisions with an effective date of November 1, 2014.

In addition to system and local capacity, BVES now has a CAISO tariff obligation to procure flexible RA resources. As noted above, the CPUC has yet to define BVES' RA requirement.

Figure 18: BVES Flexible Capacity Requirements for 2016



BVES is evaluating this situation and may issue an additional RFP for flexible RA resources.

5.C Energy Efficiency and Demand Response

The California legislature and CPUC both require that utilities manage their need for generation resources by first making an effort to reduce the need for supply.[36] While CPUC decisions and recent legislation do not specifically reference BVES, BVES continues to promote the benefits of reduced consumption. Often the lowest cost supply is obtained by convincing customers to use less energy while still providing the same level of service to the customer. As a result, the CPUC's procurement policy includes a

[34] CPUC, *Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program*, Rulemaking 11-10-023 (June 27, 2013).
[35] *California Independent System Operator Corporation*, Order on Tariff Revisions, FERC Docket ER14-2574-000, 149 FERC ¶ 61,042 (October 16, 2014).
[36] AB 2021, Levine, Chapter 734, Statutes of 2006, and the CPUC's D.04-09-060.

provision requiring that IOUs implement programs that will reduce the customer's need for energy (energy efficiency) and capacity (demand response). These customer oriented programs can take many forms and, together, are referred to by BVES as Demand Side Management (DSM).

In its decision D.09-09-047 issued September 24, 2009, the CPUC stated:

> "In Decision (D).04-09-060, the Commission articulated its goal to pursue all cost-effective energy efficiency opportunities in support of the Energy Action Plan commitment that conservation and energy efficiency are first in the "loading order" of electricity and natural gas resources. In accordance with this overarching goal, D.04-09-060 established short- and long-term numerical targets for electricity and natural gas savings. We stated that these targets must be aggressive and must stretch the capabilities and efforts of all those involved in program planning and implementation."

The loading order referred to in the CPUC decision immediately above is described as follows. Energy efficiency and demand response are top priorities for meeting California's energy needs. Next, the loading order calls for cost-effective renewable resources and distributed generation. Only after that should conventional energy resources be used to meet load.

The two basic forms of DSM are energy efficiency, which entails using less power to do the same job, and demand response, which modifies energy usage when needed for optimal grid operation. BVES' DSM programs are vital components in managing local system peaks and transmission constraints in the winter. The programs also contribute to reducing the CAISO peaks in the summer months.

BVES collects funds through its Public Purpose Program Charge to fund its DSM programs.[37] The Public Purpose Program Charge utilizes one-way balancing account treatment over the implementation cycles which allow carryover spending between years up to the total of the GRC cycle budget. This allows BVES to manage its programs over a longer timeframe.

5.C.1 Residential and Commercial Energy Efficiency

BVES' Residential Energy Efficiency Program offers lighting and high efficiency appliance rebates. Residential customers can exchange old incandescent light bulbs for new, energy efficient compact fluorescent light bulbs, or CFLs. After the inventory of CFLs is exhausted, BVES will continue the lighting exchange program but offer highly efficient LED bulbs instead of CFLs. Regarding appliances, BVES offers rebates for Energy Star labeled refrigerators, room air conditioners and high efficiency electric hot water heaters. Through its website, BVES offers energy saving tips, and an energy usage calculator that estimates an appliance's energy usage and costs.

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[37] The programs include Low Income Energy Efficiency (LIEE) or Energy Savings Assistance (ESA) and California Alternate Rates (CARE).

For commercial customers, BVES offers rebates for lighting improvements including florescent lighting retrofits, specialty screw-in lamps, low wattage T8 lamps, exterior linear fluorescent fixtures, LED exit signs, occupancy sensors, time clocks and more. In addition, BVES encourages local businesses to seek innovative, energy efficient technologies. The 2015 Commercial Energy Efficiency Grant Program awards up to $10,000 in grant funding to help businesses improve their energy usage and lower their electric bill.

Regarding BVES' lighting load, it should be noted that this load is highly correlative with BVES' peak demand. Energy efficient lighting results in a significant peak demand benefit. BVES' unique peak demand time is between 4 PM and midnight from November 1st through February 28th.

5.C.2 Energy Savings Assistance (ESA) Program

The ESA program, funded through the Public Purpose Program Adjustment Mechanism, is available only for qualifying low income residential customers. The ESA Program provides funding for energy efficient refrigerators, hard-wired compact fluorescent fixtures, compact fluorescent bulbs, LEDs, smart strip surge protectors, low-flow showerheads and weatherization measures. BVES also provides educational materials to all customers promoting the use of energy efficient appliances, weatherization materials, thermostatic controls, and life style changes.

5.C.3 Demand Response

The one DR program currently offered by BVES targets its four largest customers through a time-of-use (TOU) interruptible tariff, first approved in its 2009 GRC.[38] This tariff provides a lower rate in exchange for the customer's agreement to interrupt or reduce load when called upon by BVES to do so, even to a zero load. This DR program currently provides approximately 12 MW of coincident winter demand reduction that can be called upon during BVES' highest peak demands. With the substation expansion of capacity at Snow Summit by November 2019, driven by replacing 3 MW substation with two 10 MW substation via an added facilities rate, the interruptible load will increase by 13 MW. This will result in 23 MW of interruptible load for BVES by November 2019.

5.D Possible Rate Proposals That May Affect Resource Procurement

In its forthcoming CPUC filings, BVES may request approval for several new rates and initiatives, including a rate to support economic development, rates for electric vehicle (EV) charging stations, and additional TOU rates.

5.D.1 Electric Vehicles and Related Rate

[38] Rate Schedule A-5 TOU.

An effort to provide BVES customers with personal vehicle choices is to install electric vehicle charging stations at various locations in its service territory. With the decreased cost of electric and plug-in hybrid vehicles, there has been an increase in sales of these types of vehicles. Such a program could accommodate BVES' own customers and visitors to the Big Bear valley that own EVs and plug-in hybrids. Charging stations may be designed to encourage off peak usage, which will improve the BVES load factor and thus reduce costs to all customers. Even at peak periods, the added sales should benefit all customers, as contracts are more fully utilized and fixed charges are effectively reduced by added sales.

The CPUC allows utilities to own electric-vehicle charging infrastructures, noting that utilities will help procure, deliver, and supply electricity for plug-in electric vehicles.[39] BVES is actively monitoring and may participate in the proceeding.

While there are multiple types of charging stations available, BVES is considering three types for installation in its service territory:[40]

- Eight-hour charging stations - Usually meant to be installed at residential homes.
- Level two charging stations - Can be public charging stations and would require an average of 1 hour of charge time for 25+ miles.
- Level three (fast-charging) stations - Can be public and would require an average of 30 minutes of charge time for 80+ miles.

With the installation of EV charging stations, customers could have 3 options available for electrical usage payment:

- Tie their usage to their existing BVES account and pay when they receive their utility bill at the end of the month.
- Pay at the charging station kiosk with a credit card.
- Charge at their residence and have the usage tied to their account automatically.

On June 20, 2017, BVES has already applied for approval of its 2017 Transportation Electrification proposal (17-06) . This proposal has requested approval from CPUC for BVES to fund a Transportation Electrification, pilot project. The pilot project will fund the infrastructure labor and materials cost for up to 50 charging stations for a make ready program. The program will also fund up to 50 residential and commercial infrastructure set up for customer EV chargers. The program will also develop a TOU gram for EV charging accounts only to incentives customers to charge their vehicles during the super off-peak period, during high solar power production times and will charge higher rates during other times of the day, with the higher rate charged during BVES peak period. BVES will monitor the success of this program and use the program to gain insight into customers EV charging behavior for the BVES service area. With approximately 6,000,000 visitors to BVES and given the central location of BVES within the tourist spots of Southern California, it is imperative for BVES to test the market for EV charging stations. This should create a new end-use for electricity

[39] D. 14-12-079
[40] Source: http://www.chargepoint.com/stations/

from BVEs during the daytime, increasing the load factor for BVES, and reduce carbon emissions for Southern California. The reshaping of the load shape could also reduce the cost of supply for customers.

After sufficient studies have been conducted, BVES may apply for a separate rate tariff for EV charging stations as well as installation of sub-meters for all BVES EV customers.

The SCAQMD is finalizing plans to install two EV charging stations using a grant program funded by NRG settlement with California, for Los Angeles, Orange, and San Bernardino counties. These stations would be located in the Village retail district, the main hub for entertainment for Big Bear Lake. Tesla Motors has already made plans to install a charging station in Lake Arrowhead, within 20 miles of BVES service area. Both of these initiatives will help jump start the EV charging station trend in Big Bear Lake.

Because of the uncertainty as to the timing of the installation of charging stations, the approval of the TE BVES pilot project and adaption by customers of EV for tourist travel and for mountain living, BVES did not include the TE charging load in this IRP. BVES did this to avoid over procuring of firm power. As there is a more defined outcome for TE charging, BVES will include load projections for EV charging market in BVES service area.

5.D.2 Time-of-Use Rate

For small to medium commercial customers, BVES is also considering a voluntary TOU (Time-of-Use) rate.[41] With the current hourly breakdown set in place by BVES' hourly load research data, the voluntary rate schedule may mimic a similar type of time structure and therefore may require participants to shift their load from On-Peak hours (5:00 pm to 10:00 pm) to either Mid-Peak or Off-Peak hours to see any beneficial savings in their electricity bill. With enough participation, electrical demand will be shaved off the system at its most needed level.

Below is a typical TOU rate structure from Southern California Edison as well as a hypothetical tier structure based on BVES' TOU hours.

[41] Rate Schedules A-1 to A-3.

Typical TOU rates (SCE rates)[42]

Summer	Winter
On-Peak (Noon to 6pm) (Weekdays, excluding holidays)	
$0.19215 / kWh	
Mid-Peak (8am to Noon and 6pm to 11pm)	Mid-Peak (8am to 9pm)
$0.15897 / kWh	**$0.13834 / kWh**
Off-Peak (All other hours)	Off-Peak (All other hours)
$0.13690/ kWh	**$0.12987 / kWh**

BVES TOU Rates (Hypothetical)

Rates Ranked from 1 (most expensive) to 6 (least expensive) to Reflect BVES Average Hourly System Energy Cost Differentials

Summer	Winter
On-Peak (10am to 6pm) (Weekdays, excluding holidays)	On-Peak (5pm to 10pm) (Weekdays, excluding holidays)
3	**1**
Mid-Peak (7am to 4pm)	Mid-Peak (6am to 5pm and 10pm to Midnight)
5	**2**
Off-Peak (All other hours)	Off-Peak (All other hours)
6	**4**

The above hypothetical TOU rate structure would only be offered as a voluntary program to commercial customers willing to adjust their load usage during on-peak hours of the day.

BVES has a TOU rate for the A4 (largest commercial accounts) and A5 (largest industrial accounts) classes. The new TOU rates would be designed for the small commercial classes (A1, A2, and A3) and larger residential customers. This design will be addressed in future rate cases. With a full assessment of the anticipated impacts of

[42] Rates are based on Southern California Edison's Schedule TOU-GS-1 (effective 01.01.16)

the TOU, BVES will then include in the future IRP filings. Only existing TOU rates are in the current IRP for 2018 to 2028.

5.E Capital Projects and Other Major Initiatives

BVES is acting upon or considering the following capital investment projects and other major initiatives, furthering its goals to mitigate service interruption, obtain least-cost supply, support load growth while reducing energy costs for all customers, comply with the 50% RPS by 2030, significantly reduce carbon emissions, and promote efficiency for the customer.

- Install 8 MW AC of solar capacity at the BBARWA dry bed lake property, Baldwin Lake.
- Continue energy efficiency programs to replace inefficient lighting, targeting the residential low income customers.
- Expand service at Mammoth Resorts' Snow Summit ski resort for snowmaking. The expansion should result in an additional 13 MW capacity serving Snow Summit.
- Launch a pilot project to test the adoption of electric vehicles by BVES customers up to 50 make ready charging stations at public sites and 50 charging stations located at the customer's residence.
- Analyze the costs and benefits of acquiring up to 5 MW of stored energy capacity to balance system load, reducing energy costs for all customers.

Table 21 itemizes the potential benefits of some of the above-listed capital projects. This analysis was performed over the last two years and will be expanded to include all of these initiatives in a future IRP.

A description of each of the proposed initiatives and anticipated benefits follows.

Table 21: A Description of Proposed Initiatives and Anticipated Benefits

2018 to 2028 Average Benefit Per Year	Energy Cost Savings Shared1	Emissions Reduction Value2	Reduced Average Fixed Cost Savings3	Direct Customer Savings4	Customer Benefits5
Snow Summit Substation Expansion	$416,390	$192,340	$1,000,000	$642,296	$2,251,026
Efficiency Program Continued	-$6,448	$1,923	$188	$40,670	$36,332
Net Metering & DG Successor6	$69,982	$22,756	-$199,490	$917,818	$811,065
8 MW BVES-BBARWA Solar Project	$607,867	$106,730			$714,597
5 MW-4 hour BVES	$1,100,000	$64,234			$1,164,234
Total Benefits	$2,187,791	$387,983	$800,698	$1,600,784	$4,977,254

1) Reduced all in energy cost due to asset purchase or program implementation.
2) Reduced Carbon emission in California, valued at California and Canada GHG carbon allowance trading program.
3) Reduction in average fixed costs due to increases in energy sales
4) Benefits directed to one customer only.
5) Sum of categories 1 to 4.
6) Net Metering program discontinued. DG successor program under design. Net Metering and DG reduce retail sales and therefore increase the average fixed cost per customer.

Energy Efficiency (Lighting)

Energy efficiency programs not only reduce sales relative to end-use service, saving the customers implementing the efficiency change directly, but also produce savings to other customers not participating in the program. An efficiency program shaves the load during heavy usage hours, reducing capacity charges, and also creates energy savings by levelizing the load which allows for better fitting of contracts and reduced imbalances in scheduling. BVES analyzed a proposed targeted efficiency program for lighting bulb change-out in the residential sector to determine the impact of the program on the system load shape and to all customers in average energy costs. Also studied was the carbon pollution reduction, which is valued using the carbon allowance prices in California.

The lighting efficiency program was considered based on the results of the energy appliance saturation survey for the residential sector. The survey for BVES' residential sector is available on the BVES website for customers to take on a voluntary basis with a random drawing bi-weekly for rewards. Based on 200 results of the survey, viewing the lighting fixtures installed in homes, it was determined that a lighting retrofit program issuing 9 watt LED bulbs in place of 40+ watt bulbs for residential customers would involve replacing 47% of the sector group. This would involve changing out

140,402 bulbs in the service sector. Because there is already an administration function in the existing efficiency program and this program would add only the cost of the 9 watt bulbs, BVES estimates that at $5.40 per 9 watt bulb, the incremental efficiency program expense would be $765,189. This expense could be spread over ten years and blended into the existing efficiency program and funded by a new public purpose program. The expenses could be deducted from the gross energy cost savings to all customers in order to derive a net energy cost savings of the program. Also calculated would be the direct benefit to participating customers, the emission reduction value, and the reduced average fixed cost created by the additional capacity of 1.6 MW at peak time periods.

The lighting efficiency program could net $36,322 per year total annual benefit for all customers. An additional benefit could be the avoided cost of adding 1.6 MW to the BVES system to service the load for all customers. By reducing the capacity requirement by 1.6 MW and assuming the gas fired generation cost of capacity of $750,000 per MW, the efficiency program could allow BVES to use the efficiency gain in place of an added 1.6 MW capacity in reserve, saving BVES $1,200,000 in asset purchase with an estimated annual savings of $103,000. With a combined benefit of $139,322 per year, an added residential lighting efficiency program replacing 40+ watt bulbs with 9 watt LED bulbs appears to be an attractive program.

In addition, the 1.6 MW of shaved load through efficiency could be viewed as a 1.6 MW hedge on price spikes. If prices are extremely high and load on the system is above the amount hedged by physical assets or contracts, the reduction in load of 1.6 MW would allow BVES to reduce system average costs by avoiding the 1.6 MW per hour purchase.

Because BVES did not include the lighting program into the 2018 GRC, the 2018 IRP did not include load impact of the lighting efficiency program. BVES has observed that the lighting efficiency impact on sales is already significant and growing and will therefore not need an additional boost from a BVES funded lighting program in addition to the current efficiency programs already in place .

Energy Efficiency (Water Heater and Spa Cycling)

The demand response program for water heaters and spas could add up to 3 MW of capacity for winter time which provides added system reliability. With the possible 13 MW Mammoth substation expansion and the existing 12 MW of interruptible load currently available during winter time, it may be beneficial to have the added 3 MW of scheduled interruption (demand response) available to BVES in order to facilitate the snowmaking load without interruption for Mammoth. The water heater and spa load cycling would be on a 15-minute interval for residential and commercial customers volunteering to be on the program, with incentives at a rate to be determined.

The added 3 MW extension of interruptible load plus the 12 MW of existing interruptible load would benefit BVES in extreme load spike conditions where all available resources are needed to meet firm load. One indicator of value of the additional 3 MW of reserve capacity through the load control program would be the incremental cost of gas fired generation capacity at $750,000 / MW multiplied by the 3 MW of load interruption capability. This would equate to a $2,250,000 purchase, with a potential for annual savings of $193,500 per year. Another view of value would be the avoided cost of an expensive power purchase up to 3 MW in the day-ahead or real-time market during a spike in the CAISO. In other words, the demand reduction program through load control could add 3 MW to price hedging for BVES. The current estimate of a 3 MW water heating and spa cycling program based on received bids would be $2.4 million. The participation rate is likely to be lower for BVES than other utility service areas in California because BVES serves a ski resort and mountain biking entertainment region. Visiting customers not likely to want water heating and spa cycles altered in order for the home, hotel, or resort owner to receive energy cost benefits. BVES has not implemented the program and therefore the 2018 IRP did not include the load impact of this program in the BVES load forecast.

<u>Snow Summit Substation Expansion (13 MW)</u>

BVES and Snow Summit Resorts, a subsidiary of the new partnership of Aspen Skiing and KSL capital partners, the new owners of the Bear Mountain and Snow Summit ski resorts, are planning a 13 MW expansion of service at Snow Summit to the same level of service as Bear Mountain for snowmaking. The expansion will be in addition to the current 2.5 MW of substation capacity serving Snow Summit. The additional electric supply would displace the diesel snowmaking equipment currently used by Snow Summit. The diesel engines would remain as a backup if BVES has to interrupt supply to the ski resort, which is not anticipated in the base case and is only likely given a major supply interruption to BVES such as an SCE transmission interruption or a failure in the BVPP engines. This interruption option would be acceptable because Snow Summit currently is an A-5 primary customer with 100% of load interruptible.

The substation expansion of electric service is forecasted to yield energy savings for Snow Summit. Benefits include reduced expenditure on energy and the emission allowance payments avoided by using BVES instead of diesel. All BVES' customers would benefit from the cleaner environment and the reduced average cost of electricity resulting from an increase in sales using the same level of existing capacity for the system. Snow Summit would pay for the substation expansion via a proposed added facilities charge. The net benefits to Snow Summit included in table 21 are the energy savings less the added facilities charge. The net savings to all customers can be as high as $1,000,000 per year depending on the amount of supplemental energy usage, enabled by the substation capacity utilization increase of 13 MW. Discussions continue and the 2018 rate case outcome will determine the outcome of the substation expansion initiative. The savings are significant and BVES is hopeful that Snow Summit will agree to the expansion. BVES assumed the 13 MW expansions in substation capacity would occur by November 2019. Although two substations each with a 10 MW capacity will be installed, replacing the 3 MW facility, only 13 MW of incremental capacity will be utilized as defined by connected load of the Snow Summit snow blowers. The customer requested two 10 MW substation expansions in the expansion analysis, one at the base of the ski resort and one at the top of Snow Summit Mountain, in order to secure the power supply should a substation outage occur at the Snow Summit location .

Possible Economic Development Initiatives

Viewing Appendix G, one can see that capacity over 19 MW out of the total of 52.4 MW (assuming battery solution implemented) available is utilized less than 25% of the time. This under-utilized capacity adds to the average cost of power, as the fixed charges have to be recovered across a relatively small amount of kWh.

By attracting summer load and year-long load into the area, BVES could reduce the average cost of power. BVES could target the following industries in the BVES area by offering significant savings for a limited time period for these select industries moving into the area.

- New entertainment options
- Summer amusement park
- High altitude athletic training center
- Extension of college system
- Condo base for Mammoth resorts
- County fair festival events in summer

The rates could be designed such that the added sales due to new industries could leave the revenue results neutral; therefore, avoiding the other customers subsidizing the development. As the discounts expire with in one to five years, the added sales could reduce the average fixed cost of BVES capital on contract assets for all customers. BVEs did approach the City of Big Bear Lake about an interest in BVES implementing an economic development rate. The city manager stated that the economic development initiatives already in place are sufficient to attract new business to Big Bear Lake. The city would likely protest BVES implementing an economic development rate, even though the rate would be designed to be revenue neutral. Therefore, BVES withdrew the economic development rate from the 2018 GRC and removed the predicted impact from the load forecast of the 2018 IRP.

Utility Owned Solar on the Customer Property

BVES is currently analyzing the benefits of increasing utility solar production using customer property. This would be in addition to the BVES 8 MW solar project at BBARWA. Because of the scarcity of available property suitable for solar and the high cost, this may provide a more cost effective alternative to a traditional utility scale solar farm. BVES would first consider large projects of 5 MW or greater in order to reduce cost of solar panel installation. BVES would design leasing compensation to the customer for the land use. BVES is analyzing the benefits and rate design issues at this time. Results will be addressed in a future IRP.

Battery Technology Application to BVES System Load

BVES is analyzing the technology application and benefits of flow and Lithium Ion batteries as a tool for shaping the system load. The benefits would be to increase BVES' overall load factor and therefore reduce capacity and average costs per MWh for BVES customers. More electric sales could be made with the existing capacity, which reduces the average fixed cost of electricity to customers. Also BVES would be able to fit more solar production into the resource mix, reducing energy costs and emissions, fulfilling RPS requirements, and reducing RA requirements. The risk of price spikes and load interruption would also be reduced using flow or lithium battery technologies. BVES would also be able to better size fixed price contracts and minimize imbalances between resources and demand, thereby reducing energy costs. This technology will allow BVES to accommodate the substantial increase of renewable DG production by customers. BVES has worked with a Fractal Energy Consultants to produce technology and economic study of variety of solutions, titled, "Bear Valley Electric Solar +Storage Analysis ". The optimal energy storage solution coupled with the solar project was the 5 MW /20 MWh (4 hour) Lithium-ion NMC BESS solution. This solution would provide energy cost savings charging during low cost hours of supply and discharging during peak hours. This solution would also increase the peak capacity of the system by 5 MW and therefore reduce interruptions. This would offset RA requirements by reshaping the system load. Load swings would be reduced and load patterns levelized which would reduce RA requirements for BVES. This solution would offer a bi-directional inverter solution and therefore reduce equipment costs. The battery duty cycle would defer distribution and transmission capacity charges per MWh of system load served. The solution offers a 30% ITC solution if co-commissioned with the solar project. The 5 MW/20 MWh (4 hour) duty cycles were used in the system load forecast for the 2018 IRP.

Benefits Assessment of Potential Capital Projects

Each potential capital project and/or growth initiative was evaluated as follows:

- Reduction in total average system cost created by added volume and timing of sales relative to the existing load shape curve of the BVES system. A more leveled load shape more fully utilizes the baseload contracts, therefore reducing the average cost of power.
- Emission reduction measured in metric tons of carbon emission multiplied by the carbon allowance market price in the California and Canada GHG program forecasted by IHS-CERA.
- Reduction in fixed charges by taking total demand revenue divided by kWh sales. In turn, added sales reduce the rate requirement per kWh required to recover fixed charges. Added sales with the same transmission and distribution system and generation assets should reduce rate requirements in future rate cases.
- Direct customer benefit applies to customers in the program or substitutes electricity for more costly alternative fuel.
- The analysis for all the initiatives calculates the benefits and nets out the cost of the initiatives to determine net benefit on an average annual basis for 2018 to 2028.
- Each initiative promotes a cleaner environment by reducing carbon emissions, helping BVES achieve the CHG targets set for 2020 and 2030.

5.F Greenhouse Gas Emissions

Assembly Bill 32 (AB 32), also known as the Global Warming Solutions Act, was signed into law in 2006. AB 32 established legislation to reduce the State's greenhouse gas emissions (GHG) to 1990 levels (427 million metric tons of carbon dioxide equivalent[43] greenhouse gases) by 2020. Senate Bill 32, California Global Warming Solutions Act of 2016 mandates reduction of California Green House Gas emissions to 40 % below 1990 levels by 2030. Executive Order S-03_05 (2005) mandates a reduction of California Green House Gas Emissions to 80% below 1990 levels by 2050.

More recently, in April 2015 Governor Jerry Brown's Executive Order B-30-15 established a reduction of economy-wide CO_2 emissions to 1990 levels by 2020. The CO_2 cap and trade program began on January 1, 2013 and the program linked with Quebec on January 1, 2014. This is the market link of policies with CAISO prices as the policy targets and the technology successes of electric generation cleaning technologies, along with the growth in demand for electricity in general, influence the market prices for Carbon Allowances, which directly impacts the CAISO power prices. Also note that as Canada makes CO_2 policies more stringent, this too will impact Carbon Allowance prices for California.

The California Air Resources Board (CARB), in consultation with other agencies (e.g., CPUC and CEC), was charged with developing a comprehensive program to ensure the AB 32 GHG emissions reductions goals are achieved. This resulted in CARB's development and 2008 adoption of the Climate Change Scoping Plan (Plan).

The 2008 Plan identified specific measures within each of the State's major economic sectors, which are a mix of market-based mechanisms, regulations, voluntary actions, and economic incentives aimed at achieving the AB 32 year 2020 GHG reduction goals. Several of the 2008 Plan energy sector measures have been developed into regulations.

Throughout CARB's development of the regulations, the applicability and compliance requirements have increasingly focused on higher emitting sources. Due primarily to low emissions from the Bear Valley Power Plant (BVPP), a peaking plant, BVES currently has very limited compliance obligations under the regulations developed as part of the 2008 Plan.

Every five years CARB is required to complete Plan updates to review the major economic sector measures and determine whether the State is on track to meet the GHG reductions goals. The Plan update builds upon the initial Scoping Plan with new strategies and recommendations; it also identifies opportunities to leverage existing and new funds to further reduce GHG emissions through strategic planning and targeted

[43] "Carbon dioxide equivalent" or "CO_2 equivalent" or CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas (per § 95102 of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions).

low carbon investments. The plan also notes the state's progress toward meeting the near-term 2020 GHG emission reduction roles defined in the initial Scoping Plan.

The update, which was formally approved by CARB in May 2014,[44] focuses on nine areas that have overlapping and complementary interests that were selected to address issues that underlie multiple sectors of the state economy. The areas of focus envisioned by CARB to help achieve the 2050 GHG reduction goals include energy, transportation, agriculture, water, waste management, natural and working lands, short-lived climate pollutants, green buildings and the cap-and-trade program.

Should BVES acquire, construct or operate any additional electric generating resources (i.e. additional engine in the BVPP), it may increase its compliance obligations. It is BVES' understanding that if a generation resource emits less than 25,000 metric tons of carbon dioxide per year it does not have to participate in the Cap-and-Trade program.

Aside from any new BVES-owned generation assets being considered, any increase in GHG-related costs will be passed onto BVES via its wholesale energy purchases. Therefore, the costs of GHG and AB 32 requirements will be compared via the competitive bidding process that BVES undergoes when acquiring resources and entering into future power purchase agreements.

BVES forecast across scenarios of power supply sources support the compliance of BVES with the Energy Commission goals for reduced greenhouse emissions. BVES will be using a larger share of local solar supply in the supply portfolio over the forecast horizon of the IRP. BVES will be using more transmitted supply to hedge contracts, which will have less carbon emissions per MWh due to more solar penetration in the CAISO market. BVES will have a significant amount of load displaced by energy efficiency and customer solar generation. BVES plans to build an 8 MW solar generation facility in the BVES service area. BVES will meet the carbon emission goals and still be able to displace Snow Summit diesel generation with BVES service, which will reduce emissions for the industrial sector. See Table 22 below.

[44] See the full update at http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf (Note: CARB's link says "2013" but the update was issued May 2014.)

Table 22: Composition of Demand and Supply with Emissions Data

	Retail Sales with out Incremental Sales	Incremental Retail Sales	Incremental Retail Sales	Total Retail Sales									Reduces Retail Sales	Reduces Retail Sales				
Year	Res,Com,Ind MWh	BBARWA Sales MWh	Bear Mountain Supplemental Sales MWh	Rivalry MWh	BBARWA Solar Project Production MWh	BVPP Net Generation MWh	Local Production MWh	SCE Delivered CAISO Power to BVES in MWh	Total BVES Supply MWh	Line Losses MWh	BVES Storage Charge in MWh	BVES Storage Discharge in MWh	Residential and Commercial DG Production in MWh	Efficiency Impact on Retail Sales	Carbon Emissions Imported Power (MMT)	Carbon Emissions BVPP (MMT)	Carbon Emissions Total (MMT)	Mammoth Reduction in Emisisons Due to Supplemental Sales from BVES in MMT
2011	129,653	0	0	129,653		-205	-205	152,232	152,027	22,374			382					
2012	133,039	0	0	133,039		141	141	146,095	146,236	13,198			547					
2013	135,832	0	0	135,832		58	58	150,076	150,133	14,301			683					
2014	131,993	0	0	131,993		-141	-141	145,909	145,768	13,775			976					
2015	139,442	0	0	139,442		48	48	150,340	150,388	10,946			1,821		0.0362	0.0000	0.0362	0.0000
2016	133,873	0	0	133,873		-36	-36	156,294	156,258	22,385			4,630		0.0273	0.0000	0.0273	0.0000
2017	130,299	0	0	130,299		254	254	161,311	161,565	31,266			5,847		0.0202	0.0000	0.0202	0.0000
2018	135,730	0	0	135,730		1	1	152,017	152,018	16,288			8,039	3,130	0.0224	0.0000	0.0224	0.0000
2019	136,551	0	8,190	144,741		76	76	158,855	158,931	14,189			9,529	4,795	0.0210	0.0000	0.0210	0.0061
2020	134,869	4,473	16,263	155,605	19,769	144	19,913	151,863	171,776	16,171	7,300	7,300	10,923	6,451	0.0145	0.0001	0.0146	0.0122
2021	133,521	4,473	16,263	154,257	19,631	136	19,767	150,500	170,267	16,010	7,300	7,300	12,330	7,915	0.0127	0.0001	0.0128	0.0122
2022	132,580	4,473	16,263	153,317	19,493	128	19,621	149,592	169,213	15,897	7,300	7,300	13,604	9,690	0.0114	0.0000	0.0114	0.0122
2023	132,124	4,473	16,263	152,861	19,357	126	19,483	149,220	168,702	15,842	7,300	7,300	14,727	11,472	0.0106	0.0000	0.0106	0.0122
2024	132,217	4,473	16,263	152,953	19,221	126	19,347	149,459	168,806	15,853	7,300	7,300	15,756	12,775	0.0102	0.0000	0.0103	0.0122
2025	131,890	4,473	16,263	152,626	19,087	258	19,345	150,289	169,633	17,007	7,300	7,300	16,671	14,066	0.0109	0.0001	0.0110	0.0122
2026	131,371	4,473	16,263	152,108	18,953	257	19,210	149,850	169,060	16,953	7,300	7,300	17,433	15,234	0.0109	0.0001	0.0110	0.0122
2027	130,904	4,473	16,263	151,640	18,820	254	19,074	149,524	168,598	16,958	7,300	7,300	18,110	16,065	0.0105	0.0001	0.0105	0.0122
2028	130,453	4,473	16,263	151,189	18,689	270	18,959	150,153	169,111	17,923	7,300	7,300	18,699	16,510	0.0100	0.0001	0.0101	0.0122

Note that CHG Target for BVES by 2030 is 0.028 MMT / Year. BVES is well below the target by 2030.

5.G Summary and Conclusions

In 2017, CAISO and real time prices were higher than 2016 prices, primarily driven by higher gas prices, carbon allowance price increase, intermittent load impacts from more solar penetration in CAISO region, higher gas fired generation heat rates as more solar production penetrates the market, increases in congestion, and infrastructure interruptions for the gas market in the CAISO region.

In 2014, BVES purchased approximately 85% of its firm energy requirements through fixed priced contracts, with the remaining 15% in the day-ahead market. BVES is currently reviewing bids for firm purchase power contracts that will hedge up to 90% of all energy requirements under mostly likely scenarios and colder than normal weather. The remaining load is hedged using the BVPP gas fired generation plant. BVES is likely to adapt energy storage solution of 5 MW /15 MWh (3 hours) to accommodate the firm power contracts and insure that the use of the firm purchase contract serving the BVES energy requirements is maximized. BVES is preparing for the higher power prices and gas prices anticipated in the market prices forecasts for SP-15 from 2019 to 2024 and Southern California city gates, provided by IHS-CERA (BVES vendor of market prices and economic activity). BVES received bids for shaped volumes which align more closely with the energy usage patterns at BVES. If recommended by BVES and approved by the Commission, these purchase power contracts will provide maximum pricing coverage of BVES energy requirements while minimizing the long positions for certain hours across the forecast horizon.

Unless regulatory authorities make significant revisions to the RA policy, BVES will continue to meet its RA obligation under the CAISO Tariff based on its contribution to monthly CAISO coincident peak load and will offset its peak with the use of the Bear Valley Power Plant as a distributed-generation, behind-the-meter resource. Local RA and Flexible capacity requirements will remain an area of focus for BVES. Under the CAISO Tariff, BVES may be allocated its share of Local and Flexible RA costs if the CAISO must procure additional resources to resolve an issue on the CAISO grid. BVES intends to use RA contracts, solar production, and energy storage to meet all of the flexible, local and system requirements.

BVES continues to promote the benefits of reduced consumption, in line with state goals and regulatory policies. BVES' DSM programs are vital components in managing local system peaks and transmission constraints in the winter. The programs also contribute to reducing the CAISO peaks in the summer months.

BVES currently offers residential energy efficiency programs, mainly through lighting programs, rebates for efficient appliances, and a low-income program that funds energy efficient items for homes. The one demand response program currently offered by BVES targets its four largest customers through a time-of-use (TOU) interruptible tariff. BVES has removed the load response options that target electric hot water heaters and spas that may result in up to 3 MW of demand reduction because of the likely low customer response rate given that BVES service area is a mountain resort community and visitors or property owners are not likely to respond to interruptions of power BVES is analyzing the feasibility and economics of using a 5 MW/20 MWh (3 hour) battery solution to reshape the system load and maximize the energy sales without increasing system capacity.

BVES requested approval for pilot program providing TOU incentive rates to customers using EV chargers and requested funds for make ready charging station infrastructure development for commercial and residential use. BVES will also pursue various capital projects, furthering its goals to mitigate service interruption, obtain least-cost supply, and support load growth while reducing energy costs for all customers. The projects include new BVES-owned renewable generation (solar), the Snow Summit substation expansion, EV charging stations, and a battery solution.

BVES supply solution for meeting the forecasted energy requirements will also reduce Green House Gas Emissions (GHG) and will allow BVES to remain below the GHG emission target. This is the result of increases in energy efficiency, customer solar generation, utility owned solar generation, and a reduction in the average carbon emissions of CAISO power supply due to penetration of solar and use of stored energy. BVES supplemental sales to Snow Summit ski resort will also reduce the use of the diesel generated power supplying Snow Summit , replacing customers generation with BVES supply, which has a lower emissions rate, reducing industrial GHG in BVES service area.

6. Power Supply Costs

There are a number of components of BVES' total power supply costs, of which capacity and energy are the largest. Other costs include transmission on SCE-owned and operated facilities (including the 33 kV lines from Cottonwood Substation to Goldhill transfer station and Zanja Substation to BVES' Village Substation), transmission over the CAISO grid, ancillary services charges, reserve requirements, schedule-dispatch charges and CAISO grid-management charges, including congestion revenue rights (CRRs).

The greatest change in the wholesale markets has been the sharp decline in natural gas prices due to a maturing of the production methods for natural gas (hydraulic fracturing, or "fracking"). Meanwhile, the demand for gas has increased due to coal driven power plant retirements, growth in the US economy as a whole and especially in the petro-chemical and primary metals industry, increases in exported LNG, and increases in exported pipeline gas to Mexico. In the past, hydro production has plunged below 50% of normal production in Northern California, also boosting the demand for natural gas. Renewables in California provided relief to reduced hydro production. Intermittency of renewables production will continue to challenge the CAISO markets as gas fired generation with fast ramp-up capabilities are required to follow the renewable production declines. Careful planning will pay off significantly in mitigating the supply cost exposure due to market price volatility during these uncertain times.

6.A Forecast of Power Supply Costs

Baseline simulations of power supply costs for the period 2015 – 2024 were performed under various assumptions, including:

- BVES will apply for the permission to go into the annual hourly shaped contract with a load of 322 MWh /day for base load contract from January 1, 2019 to October 31, 2024.
- BVES will apply for the permission to go into the seasonal hourly shaped contract with a load of 570 MWh/day for January, 480 MWh/day for February, 440 MWh / day for November, and 556 MWh /day for January 1, 2019 to December 31, 2022.
- BVES meets its renewable obligations with RECs and utility owned solar.
- Any daily imbalances are either purchased or sold through the CAISO market.
- BVES will use 5 MW / 20 MWh (4 hour) battery to charge in the low cost and low demand periods and discharge during the high cost and high Demand period.
- BVES is required to enter into a new RA contract by early 2020 as the proposed RA contract expires, facing significantly higher costs for capacity by 2020 since California reserve margins may drop below 15% unless additional resources are brought on line, stimulating higher capacity prices and therefore, higher RA prices, in the power market
- The physical cap and seasonal baseload products have expired December 2017, and the annual contract expires in November 2019. BVES will enter new contracts to continue hedge coverage. BVES will use monthly contracts to fill the gap between the annual and season contract expiration and the start date of any new contracts.
- BVES pursues a solar project of 8 MW (AC) of capacity.
- BVES uses electric vehicle pilot program, time of use rate, energy efficiency lighting program, and demand response program to optimize load patterns to achieve higher load factor.

These costs are included in the power supply forecast, which assumes BVES meets its energy requirements net of customer solar production with 8 MW utility owned solar production distributed by 5 MW /20 MWh (4 hour) battery and "brown" energy and then "greens it up" with purchases of RECs to meet RPS goals.

Since the inception of the CAISO market, BVES has been able to meet its monthly short positions with Day-Ahead purchases. The price BVES pays for short positions is the Locational Marginal Price (LMP) at the default SCE load aggregation point and is calculated and published by approximately 1:00 PM the day before power flows.

BVES will continue to hedge energy requirement prices with firm power agreements after the proposed contracts expire through the forecast horizon 2018 to 2028. As BVES' new firm contracts are anticipated to expire late 2019 at the same time as reserve margins in the California market may drop below 15% and natural gas prices and renewable power supply continue to grow over the forecast horizon. Electricity and capacity prices are anticipated to increase, potentially creating price spikes in the energy and RA capacity market. The result is significant increases in energy and non-energy price components, which will affect supply costs for BVES.

BVES will pursue energy and capacity products to mitigate this potentially significant price increase from late 2018 to 2028. It should be noted that the cost analysis shown in this section is for the base case only. This case is one of many analyses performed to test strategies against uncertainties in the weather, economy, and residential solar production. The costs illustrated below represent the mid-range of supply costs BVES can expect for this planning cycle. The contract coverage will be for colder than normal weather and will cover hourly prices at the 90^{th} percentile for each day of the month. The 5 MW / 20 MWh (4 hour) battery will hedge price by absorbing contract long positions and excess solar supply and discharging this power later in the evening when higher demand and higher prices dictate greater coverage than the contract volume. The gas fired generation capacity of 8.4 MW will partially hedge power prices using gas prices for volumes exceeding contract limits and what is available from electric storage. The battery will continue to be a price hedging and capacity enhancement tool for BVES. Both functions will result in lower average power costs and greater retail sales with the same level of capacity; which reduces all in energy costs for customers.

The results of the power supply simulation are summarized in Table 23 below.

Table 23: Base Case Forecast of Power Supply Costs (Nominal)

Year	Energy Requirements MWh	Avg Energy Cost $/MWh	All in cost $/MWh	Levelized Solar Cost	Total Supply Cost With Solar & Battery $	Total Supply Cost WO Solar or Battery $
2017	161,565	$45.83	$74.19	$66.39	$11,986,429	$11,986,429
2018	152,018	$44.13	$67.64	$66.39	$10,283,049	$10,283,049
2019	158,931	$49.66	$68.30	$66.39	$10,855,743	$10,855,743
2020	171,776	$56.79	$78.99	$66.39	$13,860,287	$12,006,342
2021	170,267	$53.77	$75.61	$66.39	$13,244,183	$11,390,237
2022	169,213	$53.66	$75.58	$66.39	$13,169,392	$11,315,446
2023	168,702	$53.64	$75.83	$66.39	$13,179,464	$11,325,518
2024	168,671	$53.30	$75.44	$66.39	$13,128,822	$11,274,876
2025	168,519	$52.96	$75.53	$66.39	$13,141,090	$11,287,145
2026	167,939	$52.81	$75.70	$66.39	$13,131,519	$11,277,574
2027	167,415	$52.75	$76.01	$66.39	$13,148,339	$11,294,393
2028	166,903	$52.50	$75.74	$66.39	$13,079,901	$11,225,955

6.B SCE Transmission and Distribution Charges

After energy costs, BVES' largest cost component of total power supply costs is transmission costs. BVES pays SCE for transmission service on three SCE 33 kV lines that deliver power up the mountain to BVES, and for SCE wholesale distribution access tariff (WDAT) service (for service from SCE's Victor Substation near Victorville to SCE's Cottonwood Substation in Lucerne Valley and from SCE's Vista Substation to SCE's Zanja Substation near Redlands). BVES also pays the CAISO for transmission of energy imported into and through California. Together these transmission charges are approximately $2,700,000 annually.[45]

Currently, BVES is charged on a monthly basis for four different uses of SCE's non-CAISO grid. The four different categories of monthly charges for transmission and wholesale distribution services from SCE total approximately $900,000 annually.

6.C California Independent System Operator Charges

The CAISO charges BVES, through its Scheduling Coordinator (SC) Automated Power Exchange (APX), for ancillary services, grid management charges, imbalance energy, and CAISO uplifts.[46] Ancillary services are the services necessary to follow the moment-to-moment changes in load, such as regulation, load following, voltage support and operating reserve capacity. Grid management charges are the cost of operating the California transmission grid and include costs associated with running the CAISO markets. Imbalance energy charges apply to deviations between scheduled and metered energy and typically represent a very small portion of BVES' energy requirements. BVES will continue to minimize imbalance costs through more accurate day ahead power forecasts.

6.D Congestion Costs

Congestion Costs are one of the two components (transmission losses being the other) of the cost to deliver energy from one point to another within the CAISO. The cost of congestion is the difference in the Marginal Congestion Cost (MCC) component of the Locational Marginal Price[47] (LMP) between the price nodes specified for energy delivery and takeout. For BVES supply contracts, the source from the CAISO settlements perspective is the aggregated generation hub price for South of Path 15

[45] Including Schedule Coordinator fees.
[46] CAISO uplift charges are collected from all customers to ensure market participants, including suppliers, are made whole. They reflect costs incurred to run the market for which there is no direct assignment to specific LSEs. They are collected from all customers to ensure the CAISO market is ultimately revenue neutral.
[47] The CAISO's market design creates marginal nodal or locational prices in its Day Ahead market process. The Locational Marginal Price or LMP is the algebraic sum of the 1) Marginal Energy Cost (MCE), 2) Marginal Cost of Congestion (MCC), and 3) Marginal Loss Cost (MLC).

(TH_SP15_Gen-APND) area.[48] The sink, or takeout, point is the Southern California Edison Default Load Aggregation Price (DLAP_SCE). This price is the load weighted aggregation of all load nodes within the SCE TAC area. The Congestion Cost is calculated using the Day Ahead Market Prices as follows:

Congestion Costs = Source Marginal Congestion Cost – Sink Marginal Congestion Costs

Congestion costs can be mitigated through the use of Congestion Revenue Rights (CRRs). BVES' power contracts are for delivery to the SP15 area, so BVES must bear the cost for any congestion between SP15 and the DLAP.

As the economic conditions within California improve and system load increases, the cost of congestion will increase correspondingly to heavier system loading. Additionally, as more renewable generation is added within the CAISO area, it is expected that transmission use will increase and ultimately add to the overall cost of congestion. To mitigate this risk, BVES will continue to participate in the CAISO CRR process to secure the appropriate financial hedge to mitigate potentially increasing congestion costs or secure PPAs that deliver energy to the DLAP_SCE on behalf of BVES. The current bids for annual and seasonal shaped contracts offered power products with delivery at the DLAP_SCE and at the SP15 EZ Gen. The delivery at the DLAP_SCE was higher than the SP15 EZ Gen. BVES will evaluate if the price premium is less than the value of CRR coverage (both directions of flow) for BVES.

6.E Risk Management

As a prudent utility, BVES assumes a low-risk posture. Rather than rely substantially on the volatile, lower-cost spot market for supply, it seeks greater certainty in total power supply costs through long-term contracts rather than risk substantial upward price movements in the spot market. For the past few years, BVES has been able to fix the cost of a large percentage of its total power supply costs through long-term PPAs. This has allowed BVES to reduce its exposure to market price uncertainty, but BVES still faces other sources of risk.

BVES takes into account the Value at Risk (VAR) when determining how much of its future energy supplies to purchase through long-term PPAs. The VAR is a measure of how much total costs change when underlying variables, such as natural gas prices, change. Steps taken to mitigate VAR include the following:

- use of assets such as gas fired generation which indexes power prices to natural gas prices (which has a lower volatility rate than power prices in the Southern California market)
- use of solar project(s) to fix prices to the cost of capital of the solar facility
- use of physical call options with fixed strike prices to cap power prices

[48] The CAISO derives the aggregated generation hub price by calculating a weighted average for all generators within the SP15 area. Weights are pre-determined by the CAISO on an annual basis based on previous year output. Generator hub prices are calculated for NP15, ZP26 and SP15 areas. Generation scheduled to the aggregate generation hub is paid/charged the weighted hub price as calculated in the Day Ahead market.

- use of lighting efficiency program for the residential sector in order to shave the nighttime peaks (BVES system peak period is 7 to 10 PM) and facilitate asset and contract coverage noted above
- Battery applications to condition the system load and facilitate asset and contract coverage are under review at this time. (A future IRP will have cost benefit analysis of this technology application to BVES' system)
- use of demand response to reduce demand during periods of extreme price spikes when other hedging is fully exhausted

Additional risks BVES faces are forecast risk, market-price risk, regulatory risk, supply risk, counterparty risk, or a combination thereof. The growing portion of energy consumption from customer-owned distributed generation via the Net Metering program and its potential successor program is a significant concern. Customer solar production should increase from 1.6 % of sales in 2015 to 7% of retail sales by 2020, to 12% of sales in 2028 as this is well within the range of residential and commercial customer solar program potential (customers with less than a 5-year payback period). BVES has taken a conservative approach to forecasting retail sales in order to account for strong growth in customer owned Distributed Generation and has sized contracts and asset plans accordingly. The forecast could change significantly if the customer solar production does not grow as stated in the forecast. BVES continues to closely monitor customer Distributed Generation growth and will reassess resource requirements in future IRPs.

Forecast risk[49] is the risk associated with over- or under-forecasting BVES' retail requirements and having either too much or too little energy under long-term PPAs, requiring that BVES either buy at higher than expected costs in the spot market or sell surplus energy from existing contracts at a loss. BVES mitigates this risk by improving on forecasting models, using multiple models (regression, statistically adjusted end-use, conditional demand analysis models for individual customers) for long-term and mid-term forecasting periods, and neural network models for next day forecasting.

Market-price risk is the risk associated with entering into long-term PPAs with wholesale prices subsequently falling, such that BVES could have purchased the energy less expensively in the short-term or *spot* market. Conversely, if BVES chooses not to enter into a long-term PPA at current prices and then prices rise, BVES' price of power could rise dramatically as compared to not locking in prices at current rates. To mitigate market-price risk, BVES' planning assumptions utilize the forecasting of IHS-CERA, experts in global and regional economic trends, all facets of energy markets, policy assessments, and detail industries. IHS-CERA fully integrates all of the forecast products into one harmonious assessment of the power, fuels markets, and economy. The firm is well connected with energy, policy, manufacturing, and service sector leaders. Scenario analysis is also incorporated in the IHS-CERA support of BVES' IRP planning process. BVES incorporates this external analysis into the internal analysis used to plan for its future resource needs.

[49] BVES is refining its Load Research Project to improve forecasts; specifically, future plans are to include addition of more refined customer data via, among other methods, a pole top collection system.

Regulatory risk is the risk of changes in regulations or new regulations that increase BVES' cost of doing business. For example, if BVES takes actions to meet current regulations and regulations are subsequently changed, BVES may incur increased and unforeseen costs to (1) undo earlier actions, and (2) meet the new regulations. To mitigate regulatory risk, BVES utilizes a number of resources to assess current and future policy affecting California energy markets. BVES utilizes various legal and market consultants as well to fully assess options that BVES should take in planning for the future.

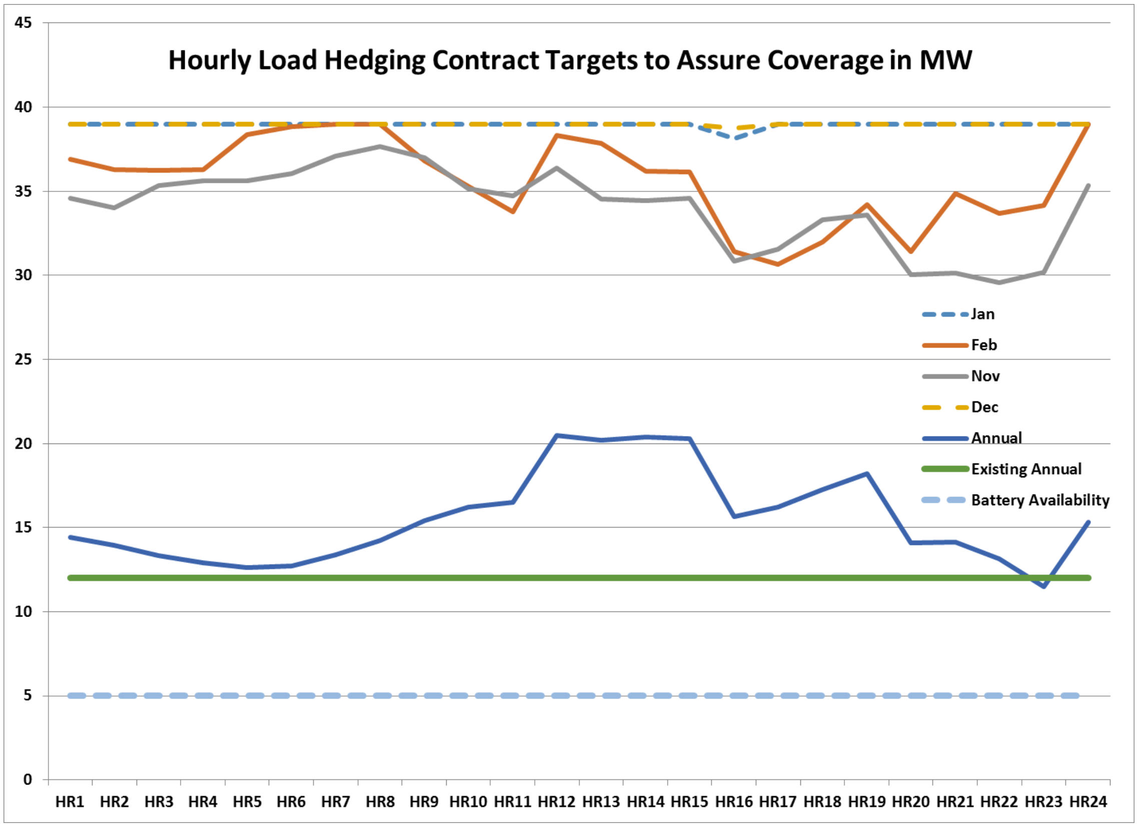
Counterparty risk is the risk that a counterparty defaults on its obligations and BVES incurs additional costs to replace energy contracted from the counterparty. To attempt to mitigate this risk, BVES utilizes parent company guarantees to the extent possible. BVES also attempts to deal primarily with companies that have good credit ratings

BVES cannot avoid all risk; risk that cannot be avoided must be managed to the extent feasible and in the most cost-effective manner. Although BVES cannot control the actions of the market or other entities, BVES seeks to design its resource acquisition strategy to minimize the financial impact of forecast and market risk. For example, BVES intends to fix the price of roughly 90 percent of its energy requirements for the next few years, which minimizes the impact of sudden price spikes in the spot markets. BVES has fixed the price of a significant amount of its energy requirements through the acquisition of competitively-priced long-term PPAs. BVES' new generation assets of solar and battery should not only secure supply but offer price hedges tied to another fuel. Diversity of resources was a key element in the development of the capacity mix available to BVES. This reduces risk for all components discussed in this section. A new technology which BVES is analyzing is the flow battery integration into the system and distribution planning process. The multiple cost reducing benefits and the constant improvement in performance and cost reduction make batteries an excellent capacity and a potentially vital instrument for BVES resource planning.

BVES will continue to monitor, assess and reduce, where possible, its regulatory risk at both the federal and state levels. Different or new energy and environmental goals, at both the federal and state levels, could add new complexity and costs to BVES' operations. Any proposed changes, both at the federal and state level, will be taken into consideration by BVES in its integrated resource planning process.

Two major goals in risk management of BVES resources are as follows. 1) Meet the capacity of the firm customers first and interruptible customers second, and 2) hedge the energy requirement expenditures in the future via fixed price contracts for both interruptible and non-interruptible customers, load conditioning through efficiency lighting programs and load control, addition of utility owned solar capacity, and the conditioning of system load to fit assets and contracts through batteries or other energy storage technology. BVES hopes to use hourly shaped contracts by season and the battery duty cycle to redistribute long positions to the short positions. See hedging example below in Figure 19. BVES used the 90th percentile of hourly load by season under colder than normal temperatures to size shaped contracts for annual and seasonal PPAs. The 5 MW / 20 MWh battery solutions will mitigate the long positions that may occur in certain hours. The contracts were shaped to minimize short and long positions for the contract coverage.

Figure 19: Hourly Load Hedging Contracts Proposal for BVES



6. F Summary and Conclusions

There are a number of components of BVES' total power supply costs, of which capacity and energy are the largest. Other costs include transmission on SCE-owned and operated facilities and CAISO charges.

The baseline simulation of power supply costs for the period 2018-2028 identified some of the important planning issues facing BVES in the nearer term (2018-2028), resulting in several mitigating actions that can be pursued. Such actions include continuing to procure approximately 90 percent or more of BVES' annual energy requirements through fixed price contracts to provide long-term cost stability. BVES could hedge the remaining portion of its energy requirement through a 8.0 MW solar project, and the 8.4 MW existing gas fired BVPP or some combination of these options. In addition, BVES may be able to shave up to 2.4 MW of load through the continuation of the existing efficiency program targeting lighting.

Regarding the outer years of late 2019 to 2028, BVES will pursue energy and capacity products to mitigate any significant price increases. BVES will also pursue battery technologies as an instrument in shaping the system load and therefore reducing energy requirement expenses. BVES has left room between energy requirement and hedged volumes in the winter in order to utilize the strategies mentioned above which reshape the load profiles in order to remove the need for some of the market hedged volumes mentioned.

As a prudent utility, BVES generally assumes a low-risk posture. Rather than rely substantially on the volatile, spot market for supply, it seeks greater certainty in total power supply costs through long-term contracts rather than risk substantial upward price movements in the spot market. For the past few years, BVES has been able to fix the cost of a large percentage of its total power supply costs through long-term PPAs. This has allowed BVES to reduce its exposure to market price uncertainty, but BVES still faces other sources of risk. Additional risks that BVES manages are forecast risk, market-price risk, regulatory risk, supply risk, counterparty risk and other types of business risk. BVES cannot avoid all risk; risk that cannot be avoided must be managed to the extent feasible and in the most cost effective manner. Although BVES cannot control the actions of the market or other entities, BVES seeks to design its resource acquisition strategy to minimize the financial impact of forecast and market risk.

Economic development will be closely monitored over the coming years in order to produce an accurate forecast and assure an adequate resource plan. Current approved expansions by customers are embedded in the current base case. Future expansion plans that are not yet announced are embedded in the base case forecast. Major game changers are not in the forecast of this IRP.

Enhancements to the forecasting process via forecast modeling, a customer survey, and a gathering of economic assumptions and economic development activities will allow BVES to enhance the risk management process and reduce the risk of price spikes. This process will also allow for improved resource planning and avoid capacity shortages and over-procurement of contract resources. Load forecasting model enhancements should further reduce forecast errors and allow for improved planning of resource requirements. Current economic development projects are covered in the base case; however, future projects which change the economic structure of the regional economy will be monitored for likelihood of occurrence and may be reflected in the forecast analysis.

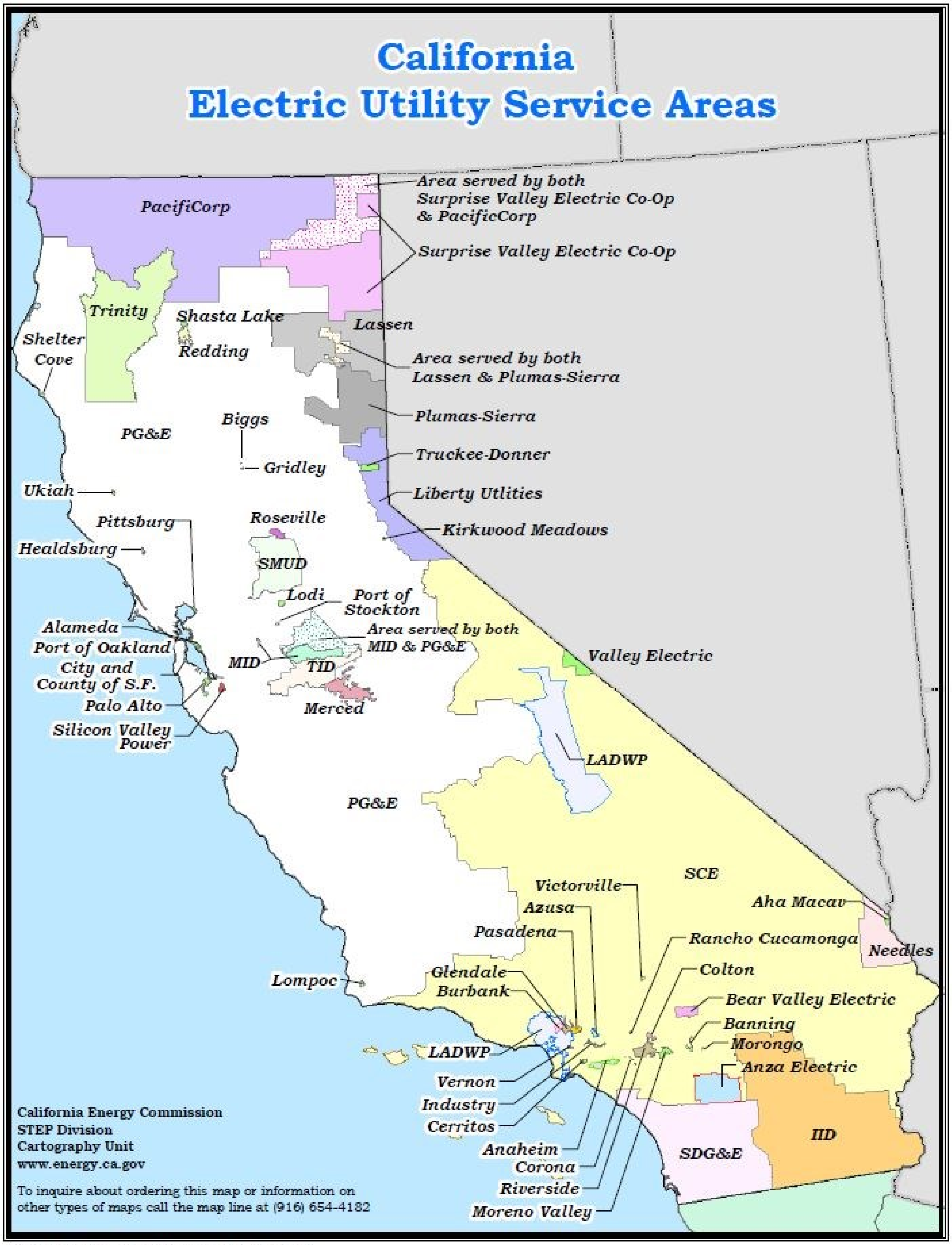
BVES will closely monitor the continued growth of customer-owned solar distributed generation. BVES must plan for this impact on the energy requirements in the future.

Utility solar projects will be reviewed as a cost mitigating instrument for energy costs for BVES. These projects may be located on customer property. If proven to be beneficial to BVES customers, BVES will pursue program and tariff designs to support implementation of these projects.

A forecast of sub-regions in the service area may be incorporated into the planning process in the future via new econometric models. This could enhance operations planning initiatives involving the sizing of equipment requirements, improve planning for Demand Response programs, and improve the efficiency of the power grid serving BVES, thereby reducing loss factors and load requirements relative to retail sales.

APPENDICES

Appendix A: Map of California Electric Utility Service Areas

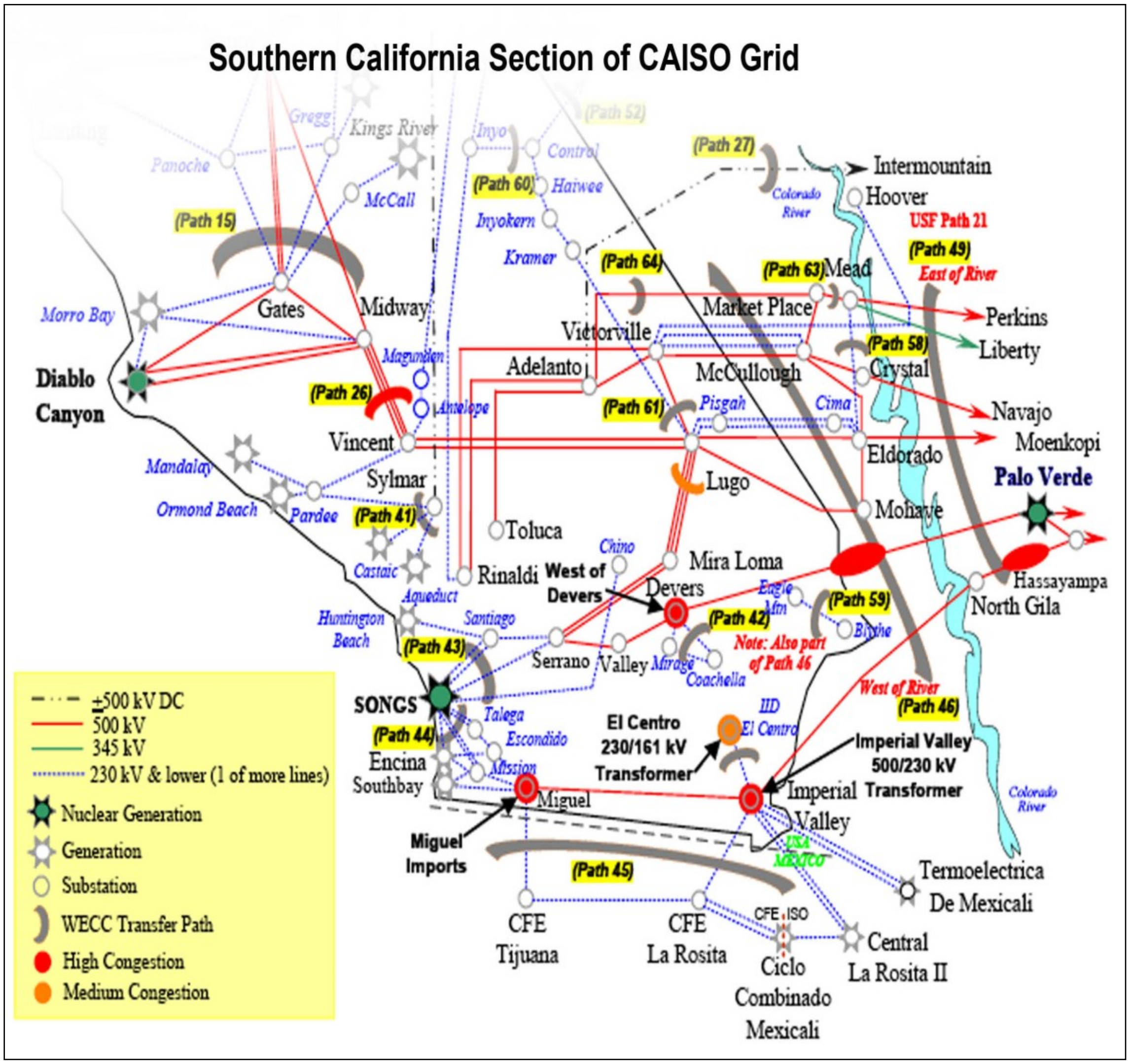


T:\Projects\CEC\Service Area\Web Maps\Service Area 8.5x11web.mxd

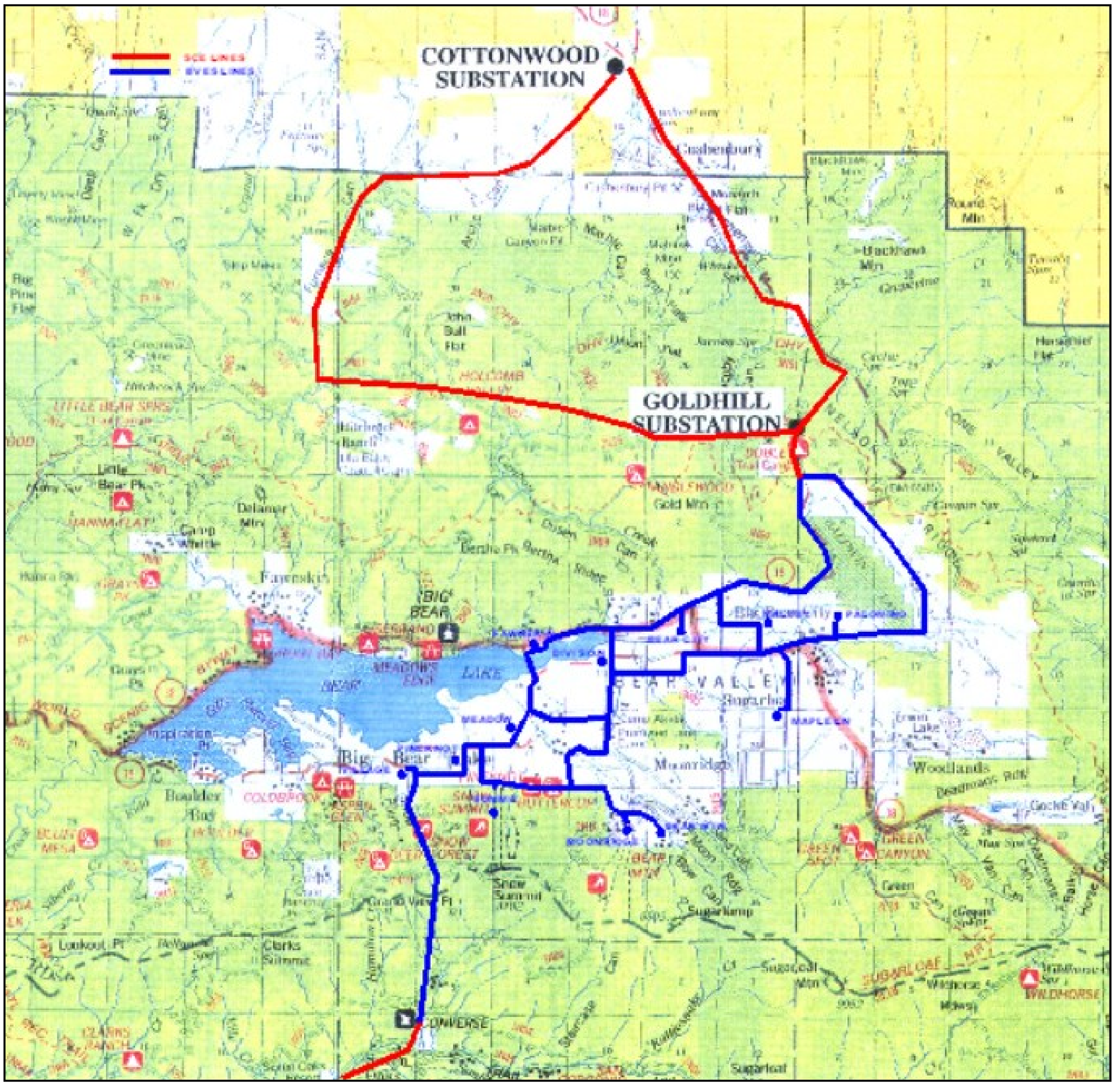
Source: California Energy Commission
http://www.energy.ca.gov/maps/serviceareas/electric_service_areas.html

Appendix B: Map of California Balancing Authorities

Appendix C: Map of Southern California Transmission System

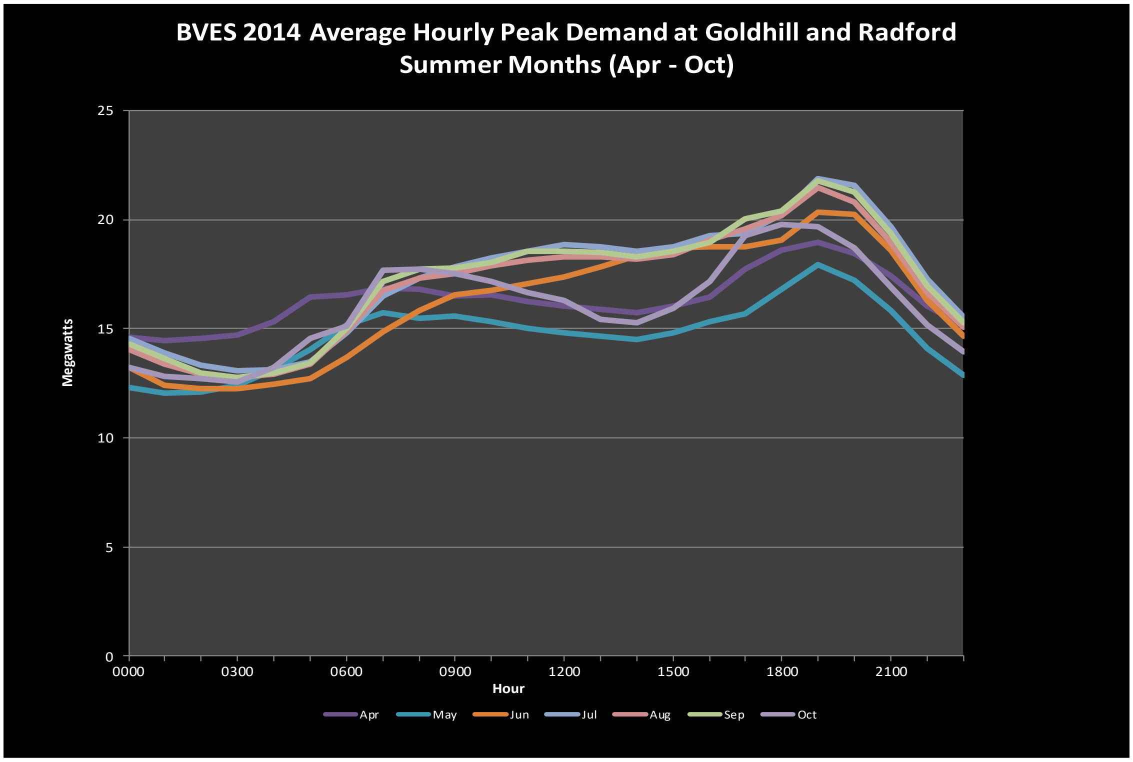


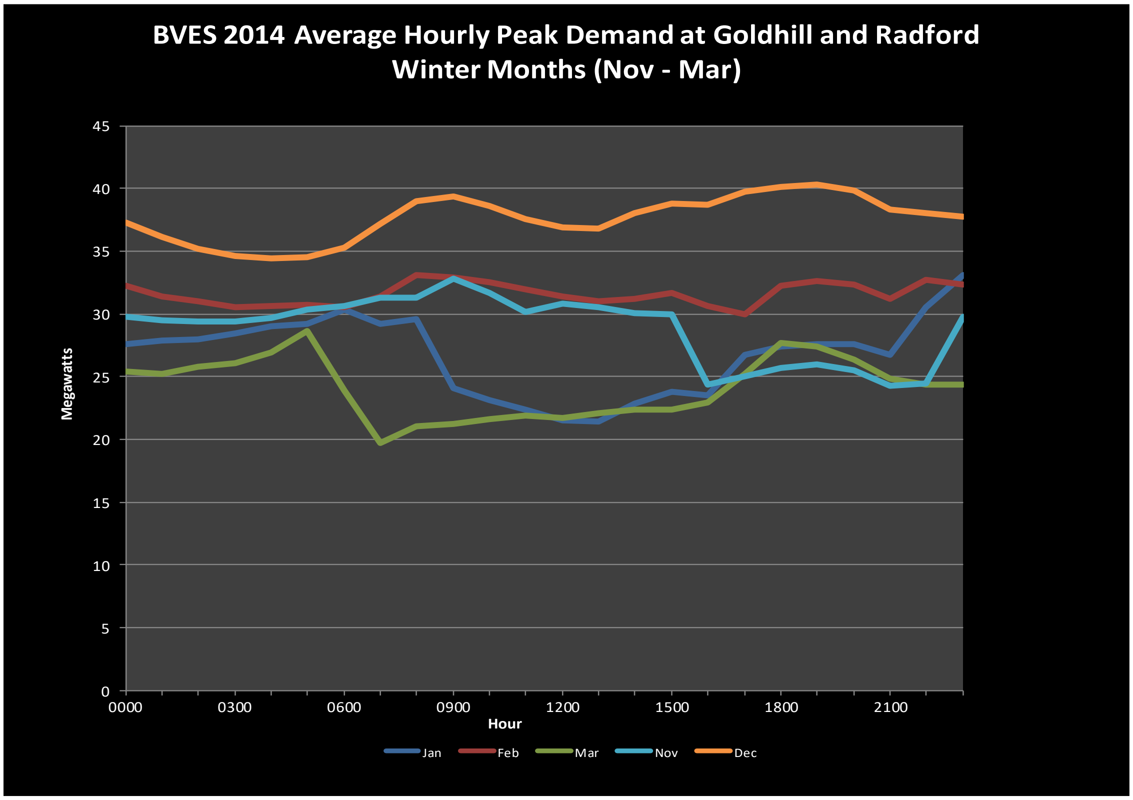
Appendix D: Map of BVES Power and Interconnectionwith SCE Power Lines



Source: Energy Information Administration (www.eia.doe.gov)

Appendix E: Monthly Average Load Curves
(Including Bear Valley Power Plant Reduction of CAISO Load)




BVES 2014 Average Hourly Peak Demand at Goldhill and Radford
Winter Months (Nov - Mar)
Megawatts
45
40
35
30
25
20
15
10
5
0
0000
0300
0600
0900
1200
1500
1800
2100
Hour
Jan
Feb
Mar
Nov
Dec

Appendix F: Glossary of Acronyms		
APX	APX, Inc.	The company that serves as the CAISO-certified Scheduling Coordinator (SC) for BVES.
BA	Balancing Authority	An entity that maintains load-resource balance within an area defined by a metered boundary. A balancing authority is the entity responsible for operating a control area. It matches generation with loads and maintains frequency within limits.
BVPP	Bear Valley Power Plant	The 8.4 MW natural gas-fired, peaking power plant owned and operated by Bear Valley Electric Service.
CAISO	California Independent System Operator Corporation	A not-for-profit public-benefit corporation charged with operating the majority of California's high-voltage wholesale power grid. The CAISO is the independent link between power plants and the utilities that serve the State's consumers, providing equal access to the grid for all qualified users and planning for transmission infrastructure.
CARB	California Air Resources Board	The "clean air agency" in the government of California, established in 1967 as a department within the cabinet-level California Environmental Protection Agency.
CO_2e	Carbon Dioxide Equivalency	A quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).
CRR	Congestion Revenue Rights	A financial mechanism designed to reduce the effect of congestion costs allocated to LSEs. A CRR is a uni-directional right to receive congestion charges from an entity causing transmission congestion.
DR	Demand Response	A set of programs offered by an LSE that provides its customers with financial incentives to reduce load in response to an event signal from the LSE.
DSM	Demand Side Management	Programs initiated by the LSE with its customers that include both EE and DR.
EE	Energy Efficiency	A set of programs offered by the LSE that provides its customers with financial incentives to install efficient electric equipment.
ESA	Energy Savings Assistance	An energy efficiency program offered by BVES under its 2013 GRC to replace the Low Income Energy Efficiency program, available only for qualifying low income residential customers.
GHG	Greenhouse Gas	A gas, such as water vapor, carbon dioxide, methane, chlorofluorocarbons (CFCs) and hydro-chloro-fluorocarbons (HCFCs), that absorbs and re-emits infrared radiation, warming the earth's surface and contributing to climate change.
GRC	General Rate Case	A process used by a utility to request recovery of its forecast revenue requirement including all operating and investment related costs. It establishes or changes the rate design and price levels to customers. It is a public process in which customers may participate.

Appendix F: Glossary of Acronyms (continued)		
ICPM	Interim Capacity Procurement Mechanism	A tariff which became effective on March 31, 2009 at the start of the new ISO market, enabling the ISO to acquire generation capacity to maintain grid reliability if (1) load serving entities fail to meet resource adequacy requirements; (2) procured resource adequacy resources are insufficient or (3) unexpected conditions create the need for additional capacity.
IHS-CERA	IHS Cambridge Energy Research Associates	A research company which provides independent analysis on energy markets, geopolitics, industry trends and strategy.
IOU	Investor Owned Utility	A privately-owned electric utility whose stock is publicly traded that is rate regulated and authorized to achieve an allowed rate of return for its shareholders.
IRP	Integrated Resource Plan	A document for planning, evaluating and acquiring generation resources to meet forecasted energy requirements. The goal of the IRP is to identify a mix of firm generation resources that provides reliable, least-cost energy to serve the needs of electric customers.
IRRP	Interim Reliability Requirements Program	A program which implements Resource Adequacy established by State authorities, including the CPUC and other local regulatory authorities, intended to remain effective until implementation of Market Redesign and Technology Upgrade.
LAP	Load Aggregation Point	A set of physical or theoretical Pricing Nodes as specified in the CAISO Tariff that are used for the submission of Bids and Settlement of Demand.
LCR	Local Capacity Resource	Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load or Proxy Demand Resource that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.
LMP	Locational Marginal Pricing	A market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid. Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity - the one that balances supply and demand - to market.
LSE	Load Serving Entity	An entity that provides electric power service to end-use customers. LSEs include but are not limited to IOUs, Energy Service Providers, Community Aggregation Groups and publicly-owned utilities.
MCC	Marginal Congestion Cost	The component of LMP at a node that accounts for the costs of congestion, as measured between that node and a reference bus.
MRTU	Market Redesign and Technology Upgrade	CAISO market redesign process implemented on April 1, 2009, intended to improve the reliability of energy supply and transmission grid management.
MSA	Metropolitan Statistical Area	A geographical region with a relatively high population density at its core and close economic ties throughout the area, such as Los Angeles-Long Beach-Santa Ana.
NEM	Net Energy Metering	A program and associated tariff which allows customers to use renewable resources (e.g., solar panels) to generate electricity and offset their consumption with their own power production.

Appendix F: Glossary of Acronyms (continued)		
PPA	Power Purchase Agreement	Power contract between an LSE and an electricity generator.
RA	Resource Adequacy	CPUC mandated level of capacity and reserves that each LSE must have to meet their customers' demand that is coincident with CAISO's peak load.
RFP	Request For Proposals	A document that an organization posts to elicit competitive bids from potential suppliers of a product or service.
RPS	Renewables Portfolio Standard	CPUC/Legislature requirement that all LSEs must obtain a specific percentage of the energy they sell to their retail customers through renewable generation sources.
SC	Scheduling Coordinator	An entity certified and authorized by the CAISO to schedule load and generation resources in the CAISO market.
SENA	Shell Energy North America	An energy provider with which BVES has contracted for multiple energy products to be delivered over the period 2009 through 2013.
SMJU	Small and Multi-Jurisdictional Utilities	CPUC-regulated utilities other than Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric, which serve retail customers in California.
SP15	South of Path 15	For purposes of energy pricing and definition of delivery location, the State is divided into three zones and scheduling points: SP15 in the south, NP15 in the north, and ZP26 in the center.
VAR	Value at Risk	A technique used to estimate the probability of portfolio losses based on the statistical analysis of historical price trends and volatilities.
WDAT	Wholesale Distribution Access Tariff	A fee levied by a transmission owner to an LSE with no transmission ownership for use of their transmission equipment.

Appendix G: Composition of BVES Hourly Load

	Peak	Energy Req.	Load Factor	Hours BVES System Above:										Sales
Year	MW	MWh	%	5 MW	10 MW	15 MW	20 MW	25 MW	30 MW	35 MW	40 MW	45 MW	**50 MW**	KWh
2011 Actual	40.1	152,027	43.31%	8,760	8,760	5,320	1,817	1,003	376	48	1	0	**0**	133,709
2012 Actual	43.6	146,236	38.29%	8,760	8,760	5,088	1,192	594	302	69	14	0	**0**	128,616
2013 Actual	38.8	150,133	44.16%	8,760	8,757	5,340	1,591	796	418	49	0	0	**0**	132,043
2014 Actual	46.4	145,768	35.85%	8,760	8,760	5,105	1,124	565	281	95	29	4	**0**	128,204
2015 Actual	46.0	150,388	37.33%	8,760	8,755	4,799	1,564	907	539	189	46	3	**0**	132,267
2016 Actual	42.7	156,258	41.77%	8,760	8,760	6,348	1,918	764	288	57	13	0	**0**	137,430
Normal Weather														
2017	42.7	161,565	43.21%	8,760	8,760	7,051	2,189	847	300	57	13	0	**0**	142,098
2018	45.3	152,018	38.32%	8,760	8,759	5,484	1,604	783	335	140	33	1	**0**	133,701
2019	52.4	158,931	34.62%	8,760	8,760	5,587	1,857	1,086	662	344	168	55	**21**	139,781
2020	52.4	171,776	37.42%	8,760	8,760	6,111	2,430	1,758	1,137	536	289	104	**40**	151,078
2021	52.4	170,267	37.09%	8,760	8,760	5,925	2,381	1,741	1,106	521	281	99	**37**	149,751
2022	52.4	169,213	36.86%	8,760	8,760	5,804	2,354	1,729	1,088	512	274	94	**34**	148,824
2023	52.4	168,702	36.75%	8,760	8,760	5,733	2,337	1,725	1,072	504	273	92	**34**	148,375
2024	52.4	168,806	36.77%	8,760	8,760	5,747	2,339	1,726	1,070	503	271	92	**34**	148,466
2025	52.4	169,633	36.96%	8,761	8,252	5,670	2,551	1,748	1,212	607	339	195	**63**	149,194
2026	52.4	169,060	36.83%	8,760	8,409	5,435	2,511	1,745	1,211	598	341	197	**60**	148,690
2027	52.4	168,598	36.73%	8,760	8,410	5,389	2,495	1,737	1,197	595	339	195	**59**	148,283
2028	52.4	169,111	36.84%	8,781	8,427	5,396	2,511	1,752	1,200	601	338	199	**71**	148,735
25 % Colder Temperatures														
2018	47.8	154,985	37.00%	8,760	8,758	5,691	1,816	863	414	191	56	7	**0**	136,311
2019	52.4	162,318	35.36%	8,760	8,758	5,759	2,051	1,158	775	412	223	86	**28**	142,760
2020	52.4	174,791	38.08%	8,760	8,760	6,220	2,553	1,799	1285	633	339	150	**56**	153,730
2021	52.4	173,145	37.72%	8,760	8,759	6,004	2,495	1,784	1250	607	330	144	**54**	152,282
2022	52.4	172,042	37.48%	8,760	8,758	5,874	2,457	1,771	1229	596	326	137	**53**	151,312
2023	52.4	171,527	37.37%	8,760	8,758	5,812	2,445	1,768	1221	592	322	134	**52**	150,859
2024	52.4	171,652	37.39%	8,760	8,758	5,821	2,447	1,768	1222	592	322	134	**53**	150,969
2025	52.4	176,046	38.35%	8,761	8,211	5,732	2,791	1,933	1,495	846	461	282	**136**	154,834
2026	52.4	175,411	38.21%	8,760	8,355	5,520	2,767	1,905	1,492	831	467	285	**135**	154,275
2027	52.4	174,901	38.10%	8,760	8,351	5,493	2,748	1,900	1,482	820	459	281	**128**	153,827
2028	52.4	175,369	38.20%	8,781	8,368	5,485	2,758	1,912	1,484	827	460	285	**136**	154,239
25 % Warmer Temperatures														
2018	42.5	148,227	39.80%	8,760	8,759	5,121	1,378	679	277	98	9	0	**0**	130,366
2019	52.4	154,796	33.72%	8,760	8,759	5,239	1,622	995	550	293	120	40	**16**	136,144
2020	52.4	167,335	36.45%	8,760	8,760	5,772	2,253	1,676	953	434	230	72	**19**	147,172
2021	52.4	165,786	36.12%	8,760	8,760	5,592	2,199	1,661	925	418	220	67	**19**	145,810
2022	52.4	164,765	35.89%	8,760	8,759	5,444	2,161	1,649	904	409	214	65	**17**	144,912
2023	52.4	164,300	35.79%	8,760	8,759	5,389	2,150	1,644	892	404	211	65	**17**	144,503
2024	52.4	164,457	35.83%	8,760	8,759	5,405	2,153	1,645	893	406	210	65	**17**	144,641
2025	52.4	164,687	35.88%	8,761	8,229	5,450	2,389	1,644	1,020	492	268	139	**45**	144,844
2026	52.4	164,159	35.76%	8,760	8,394	5,216	2,356	1,643	1,012	487	268	141	**46**	144,379
2027	52.4	163,767	35.68%	8,760	8,394	5,183	2,346	1,640	1,001	483	266	135	**45**	144,034
2028	52.4	164,316	35.80%	8,781	8,418	5,178	2,353	1,653	1,002	487	265	139	**49**	144,517
1) Note that although load is interrupted above 50 MW, BVES can serve load up to 52.4 assuming 5 MW battery solution implemented.														
Also , load can be served up to 56.4 MW for a duration of 3 hours. The load served above 50 MW has some degree of uncertainty.														

The chart above reflects the number of hours that the BVES system load is above certain MW thresholds.

Appendix H: BVES Carbon Emissions Under the Normal Weather Rivalry (Base Case) Scenario

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BVES Sales (MWh), NEM Included	129,653	133,039	135,832	131,993	139,442	133,873	130,299	135,730	136,551	134,869	133,521	132,580	132,124	132,217	131,890	131,371	130,904	130,453
RPS Requirement					23.15%	25.00%	27.00%	29.00%	31.00%	33.00%	34.700%	36.400%	38.100%	39.800%	41.500%	43.200%	44.900%	46.600%
RECS and Solar					32,278	33,468	35,181	39,362	42,331	44,507	46,332	48,259	50,339	52,622	54,734	56,752	58,776	60,791
Purchased Power					107,164	100,405	95,119	96,369	94,220	70,593	67,559	64,828	62,428	60,373	58,069	55,666	53,308	50,973
Solar Project Output										19,769	19,631	19,493	19,357	19,221	19,087	18,953	18,820	18,689
BVPP Net Generation					0	0	0	1	76	144	136	128	126	126	279	279	272	288
Emmisison in MT					0.03624	0.027326	0.020176	0.022357	0.021015	0.014587	0.012774	0.011426	0.010641	0.010279	0.010979	0.01105	0.010555	0.010083
BVPP Emmission					0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0001	0.0001	0.0001	0.0001
Purchase Power Emmission					0.03624	0.0273257	0.020176	0.0223562	0.0209855	0.0145313	0.0127214	0.0113767	0.0105926	0.0102302	0.0108723	0.0109433	0.0104514	0.0099728
Mammoth Displaced Generation Thorugh Supplemental Sales in MWh					0	0	0	0	8,190	16,263	16,263	16,263	16,263	16,263	16,263	16,263	16,263	16,263
Diesel Eng Heat Rate Btus per KWh					10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300	10,300
Diesel Fuel Heat Content Btus per Gal					138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690	138,690
Gallons of Diesel for Generation					0	0	0	0	608,241	1,207,794	1,207,794	1,207,794	1,207,794	1,207,794	1,207,794	1,207,794	1,207,794	1,207,794
Lbs of Emmisison Per Gal of Diesel					22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Emmisisons of Diesel in MMT					0.0000	0.0000	0.0000	0.0000	0.0061	0.0122	0.0122	0.0122	0.0122	0.0122	0.0122	0.0122	0.0122	0.0122
Purchase Power for Mammoth Emmisisons					0.0000	0.0000	0.0000	0.0000	0.0018	0.0033	0.0031	0.0029	0.0028	0.0028	0.0030	0.0032	0.0032	0.0032
Mammoth Displaced Generation Thorugh Supplemental SalesReduced Emmissions in MMT					0.0000	0.0000	0.0000	0.0000	0.0043	0.0088	0.0091	0.0093	0.0094	0.0094	0.0091	0.0090	0.0090	0.0090

Appendix I:
BEAR VALLEY ELECTRIC SERVICE

ALTERNATIVE IRP PLAN
UNDER D.12-02-018

Appendix I: Alternative IRP Plan Under D.18-02-018

D. 18-02-018, Ordering Paragraph #14 states:

14. All load serving entities with annual load forecasts that are 700 gigawatt hours or less in California in any of the first five years of the integrated resource plan planning horizon, except PacifiCorp, shall be required to file Alternative Plans consisting of at least the following information:

- *California Energy Commission (CEC) Form S1.*
- *CEC Form S2 or Energy Information Administration (EIA) Form 861 or EIA Form 861S.*
- *CEC Power Content Report.*
- *A description of the treatment of disadvantaged communities, as required in Ordering Paragraph 6 above.*
- *A description of how planned future procurement is consistent with the Greenhouse Gas Planning Price or its individual Greenhouse Gas Benchmark.*
- *A Conforming Portfolio consistent with the Reference System Portfolio.*
- *A description of any alternative or preferred portfolios along with identification and justification for any deviations in assumptions from the Reference System Portfolio.*
- *A description of how the LSE's preferred portfolio is consistent with each relevant statutory and administrative requirement.*
- *An action plan that includes all of the actions the LSE proposes to take in the next one to three years to implement its plan.*
- *A description of any barriers and lessons learned from the prior IRP and/or procurement cycle.*

1. California Energy Commission (CEC) Form S1.

State of California
California Energy Commission
ELECTRICITY RESOURCE PLANNING FORMS
CEC Form S-1 Capacity Resource Accounting Table (issued 12/2016)

LSE Names on Admin Tab

2018 MW numbers are illustrative

Yellow fill relates to an application for confidentiality

Where cell specifies more than one datum, separate data with semicolon

Bold font cells sum automatically

Data input by User are in dark green font

line	**Capacity Resource Acocunting Table (MW)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	PEAK LOAD CALCULATIONS	(↓ Prior Forecasts ↓)		(Forecast Supply →)									
1	Forecast Total Peak-Hour 1-in-2 Demand	46.0	42.7	40.5	45.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4
2a	ESP Demand: Exisitng Customer Contracts												
2b	ESP Demand: New and Renewed Contracts												
2c	ESP Demand in PG&E service area												
2d	ESP Demand in SCE service area												
2e	ESP Demand in SDG&E service area												
3	Additional Achievable Energy Efficiency (-)						-9.5	-9.5	-9.5	-9.5	-9.5	-9.5	-9.5
4	Demand Response/Interruptible Programs (-)	-9.0	-9.0	-9.0	-9.0	-18.1	-18.1	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0
5	**Adjusted Demand: End-Use Customers**	**37.0**	**33.7**	**31.5**	**36.3**	**34.3**	**24.8**	**24.9**	**24.9**	**24.9**	**24.9**	**24.9**	**24.9**
6	Coincidence Adjustment (-)	-4.6	-6.1	-10.6	-11.3	-6.7	-6.7	-6.8	-6.8	-6.8	-6.8	-6.8	-6.8
7	**Coincident Peak-Hour Demand**	**32.4**	**27.6**	**20.9**	**25.1**	**27.6**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**
8	Required Planning Reserve Margin	4.9	4.1	3.1	3.8	4.1	2.7	2.7	2.7	2.7	2.7	2.7	2.7
9	Credit for Imports That Carry Reserves (-)												
10	Firm Sales Obligations												
11	**Firm LSE Procurement Requirement**	**46.4**	**44.0**	**45.3**	**51.3**	**45.2**	**34.3**	**34.3**	**34.4**	**34.4**	**34.5**	**34.5**	**34.5**
	CAPACITY SUPPLY RESOURCES												
12a	**Total Fossil Fuel Supply**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**
12b	Natural Gas Unit 1	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
12c	[state fuel; then list each resource, e.g. Natural Gas, Fossil Unit 2]	0	0	0	0	0	0	0	0	0	0	0	0
12d	[state fuel; then list each resource, e.g. Natural Gas, Fossil Unit N; list of planned resources last]				0								
13a	**Total Nuclear Supply**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
13b	[Nuclear Unit 1]				0								
13c	[Nuclear Unit 2]				0								
14a	**Total Hydroelectric Supply**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
14b	Total: Hydro Supply from Plants larger than 30 MW				0								
14c	Total: Hydro Supply from Plants 30 MW or less				0								
15a	**Total Utility-Controlled Renewable Supply**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
15b	Solar; Renewable Project 1				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15c	[state fuel; then list each resource, e.g. Geothermal: Renewable Project 2]				0								
15d	[state fuel; then list each resource, Wind: Renewable Project N; list planned resources last]				0								
17a	**Total Qualifying Facility (QF) Contract Supply**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
17b	Biofuels												
17c	Geothermal												
17d	Small Hydro												
17e	Solar												
17f	Wind												
17g	Natural Gas												
17h	Other												
line	**Capacity Resource Accounting Table (MW)**	**2015**	**2016**	**2017**	**2,018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
18a	**Total Renewable Contract Supply**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
18b	Renewable DG Supply	0	0	0	0	0	0	0	0	0	0	0	0
18c	[state fuel; then Renewable Contract 1 (Supplier Name)]												
18d	[Small Hydro; then enewable Contract 2 (Supplier Name)]												
18e	[Solar; then Renewable Contract N, list planned resources last]												
19a	**Total Other Bilateral Contract Supply**	**32**	**30.8**	**26**	**27.5**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
19b	Non-Renewable DG Supply	0	0	0	0	0	0	0	0	0	0	0	0
19c	[state fuel if known; then Annual Other Bilateral Contract 1 (EDF)]	12	12	12	12								
19d	[Physical Call Option: Other Bilateral Contract 2 (EDF)]	7	7	7									
19e	[Seassonal Bilateral Contract 3 (Shell)]	7	7	7									
19f													
19n	Planned Resources: list each on lines inserted below this line.												
19o	Future Annual Contract (May 23,2018 RFP,new RFP)					16	16	16	16	16	16	16	16
19p	Future Seassonal Contract (May 23,2018 RFP,new RFP)					18	18	18	18	18	18	18	18
19q	LI or Flow 5 MW /20 MWh battery					5	5	5	5	5	5	5	5
20	Short-Term and Spot Market Purchases (and Sales)	6	4.8		16								
	CAPACITY BALANCE SUMMARY												
21	**Total: Existing and Planned Supply**	**46.4**	**44.0**	**34.4**	**51.4**	**47.4**	**47.4**	**47.4**	**47.4**	**47.4**	**47.4**	**47.4**	**47.4**
22	Firm LSE Procurement Requirement	**46.4**	**44.0**	**45.3**	**51.3**	**45.2**	**34.3**	**34.3**	**34.4**	**34.4**	**34.5**	**34.5**	**34.5**
23	**Net Surplus (or Need)**	**0.0**	**0.0**	**-10.9**	**0.1**	**2.2**	**13.1**	**13.1**	**13.0**	**13.0**	**12.9**	**12.9**	**12.9**
24	Generic Renewable Supply												
25	Generic Non-Renewable Resources												
26	Specified Planning Reserve Margin	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%

		MW	MW
line	**Historic LSE Peak Load:**	**Year 2015**	**Year 2016**
27	Annual Peak Load / Actual Metered Deliveries	45.0	39.4
28	Date of Peak Load for Annual Peak Deliveries	12/26/15	12/24/16
29	Hour Ending (HE) for Annual Peak Deliveries	19	18
30	Interruptible Load called on during that hour (+)	0.0	0.0
31	Self-Generation and DG Adjustments	13.1	13.1
32	Adjustments for Major Outages	0.0	0.0
33	Adjusted Annual Peak Load	**58.1**	**52.5**

Lines	Notes
31	Snow Summit Generation for Snow Making
31	BBARWA 600 KW + 500 KW=1,100 KW
19q	Batterry Discharge over 4 hour period will occure during peak
1	Assuming battery 5 MW/20 MWh
4	Snow Summit is interruptable customer with back up generation, will subscribe to BVES added facilities of two substations 10 MW each.
15b	Bear Valey Solar Project 8 MW Single Axis Tracking starting jan 2020 does not offer capacity support during BVES peak hours 7-10 PM

2. Energy Information Administration (EIA) Form 861

BVES Energy Information Administration (EIA) Form 861 is submitted herewith. EIA Form 861 is attached as “EIA Form 861”

3. California Energy Commission Power Content Report

Version: May 2018

ANNUAL REPORT TO THE CALIFORNIA ENERGY COMMISSION:
Power Source Disclosure Program
Schedule 1 and 2, applicable to: Load Serving Entities
For the Year Ending December 31, 2017

Load serving entities are required to use the posted template and are not allowed to make edits to this format. Please fill out the company name and contact information.

GENERAL INSTRUCTIONS

COMPANY NAME
Bear Valley Electric Service (U 913-E)

PRODUCT NAME (If Multiple Products Offered)

CONTACT INFORMATION	
Name	Sean Matlock
Title	Customer Care and Operations Support Superintendant
Mailing Address	42020 Garstin Dr.
City, State, Zip	Big Bear Lake, CA 92315
Phone	(909) 866-4678 ext 120
E-mail	smatlock@bves.com
Website for PCL Posting	https://www.bves.com/customer-service/rates-&-regulations/rules/

Please fill out the schedules that apply to your company's filing requirements. Provide the annual report and attestation together in PDF format and the annual report in an excel file by email to PSDprogram@energy.ca.gov. Remember to fill in the company name above, submit separate reports and attestations for each additional product if multiple electric service products are offered. Report procurements in MWh (not kWh).

NOTE: Information submitted in this report is not automatically held confidential. If your company wishes the information submitted to be considered confidential an authorized representative must submit an application for confidential designation (CEC-13), which can be found on the California Energy Commissions's website at http://www.energy.ca.gov/commission/chief_counsel/documents/CEC13.pdf

If you have questions, contact PSD staff at PSDprogram@energy.ca.gov or (916) 653-6222.

Version: May 2018

ANNUAL REPORT TO THE CALIFORNIA ENERGY COMMISSION: Power Source Disclosure Program

For the Year Ending December 31, 2017
SCHEDULE 1: POWER PROCUREMENTS AND RETAIL SALES
Applicable to: Load Serving Entities

INSTRUCTIONS: Enter information about power procurements supporting all electricity products for which your company is filing the Annual Report. If you need additional rows, add them from the INSERT menu. Please list all purchases (Specified and Unspecified purchases) as line items under the Facility Name heading. If a procurement was for unbundled RECs include the term "REC Only" in parentheses after the facility name in the Facility Name column, and categorize the power as the fuel type of the generating facility from which the unbundled REC was derived. If procured power was from a transaction that expressly transferred energy only and not the RECs associated with that energy, identify the power as "Unspecified Power" in the Fuel Type column.

ALL PROCUREMENTS (Specified and Unspecified)

Facility Name	Unit No.	Fuel Type	Location (State or Province)	RPS ID	WREGIS GU ID	EIA ID	FERC QF ID	Gross MWh Procured	MWh Resold or Self-Consumed	Net MWh Procured
										0
										0
Elkhorn Valley Wind Farm - Elkhorn Valley Wind Farm (REC Only)		Wind	OR	61034	W186			1282.00		1282
Juniper Canyon - Juniper Canyon (REC Only)		Wind	WA	61202	W1690			340.00		340
Leaning Juniper II - Leaning Juniper II (REC Only)		Wind	OR	61200	W1689			3184.00		3184
Monroe Street HED - Monroe Street HED (REC Only)		Hydroelectric Water	WA	60496	W218			5000.00		5000
Rolling Hills - Rolling Hills (REC Only)		Wind	WY	60806	W928			4000.00		4000
Seven Mile Hill I - Seven Mile Hill I (REC Only)		Wind	WY	60807	W975			5000.00		5000
Sierra Pacific Burlington - Sierra Pacific Burlington (REC Only)		Biomass	WA	60596	W1491			302.00		302
Sierra Pacific Burlington - SPI Burlington Onsite Load (REC Only)		Biomass	WA	60596	W2042			2697.00		2697
Sierra Pacific Burney Facility - SPI Burney Onsite Load (REC Only)		Biomass	CA	60087	W1734			1771.00		1771
Sierra Pacific Ind. (Lincoln) - SPI Lincoln Onsite Load (REC Only)		Biomass	CA	60088	W1735			5320.00		5320
Sierra Pacific Ind. (Quincy) - SPI Onsite Load (REC Only)		Biomass	CA		W1755			858.00		858
Sierra Pacific Inc. (Quincy) - SPI Quincy Onsite Load (REC Only)		Biomass	CA	60089	W1736			4252.00		4252
Sierra Pacific Sonora - SPI Sonora Onsite Load (REC Only)		Biomass	CA	60576	W2842			2419.00		2419
Top of the World - Top of the World (REC Only)		Wind	WY	61199	W1749			6000.00		6000
								42425.00		
										0
Bear Valley Power Plant		Natural Gas	CA			56346		777.70	523.7	254
Unspecified-CAISO / EDF Trading North America LLC		Unspecified Power						105120.00		105120
Unspecified-CAISO / Shell Energy North America (US), L.P.		Unspecified Power						18725.00		18725
Unspecified / CAISO		Unspecified Power						7343.10	7820.8	-478
										0

Total Net Purchases	166,046

note: if you subtract the REC only purchases from the actual MWh purchased, you get a total net purchase of 123,621, which is 3,790 MWh less than total sales.

Total Retail Sales	127,411

Version: May 2018

ANNUAL REPORT TO THE CALIFORNIA ENERGY COMMISSION:
Power Source Disclosure Program
For the Year Ending December 31, 2017
SCHEDULE 2: ANNUAL POWER CONTENT LABEL CALCULATION
Applicable to: Load Serving Entities

INSTRUCTIONS: Total specific purchases (by fuel type) and enter these numbers in the first column. Null power purchases should be included with Unspecified Power. REC only purchases should be included as part of the fuel type they represent. Total retail sales information from Schedule 1 will autopopulate on this schedule. Any difference between total net purchases and total retail sales will be applied pro-rata to each non-renewable fuel type. Each fuel type total will them be devided by retail sales to calculate fuel mix percentages.

	Net Purchases (MWh)	Percent of Total Retail Sales (MWh)
Specific Purchases		
Renewable	42,425	33%
Biomass & Biowaste	17,619	14%
Geothermal	-	0%
Eligible hydroelectric	5,000	4%
Solar	-	0%
Wind	19,806	16%
Coal	-	0%
Large Hydroelectric	-	0%
Natural Gas	254	0%
Nuclear	-	0%
Other		0%
Total Specific Purchases	**42,679**	**33%**
Unspecified Power (MWh)	**123,367**	**67%**
Total	**166,046**	**100%**
Total Retail Sales (MWh)	**127,411**	

COMMENTS:

Version: May 2018

ANNUAL REPORT TO THE CALIFORNIA ENERGY COMMISSION:
Power Source Disclosure Program
For the Year Ending December 31, 2017
ATTESTATION FORM
Applicable to: All participants in the Power Source Disclosure Program

I, Joseph Phalen, [title] Energy Resource MGR, **declare under penalty of perjury, that the statements contained in Schedules** 1 & 2 **are true and correct and that I, as an authorized agent of** Bear Valley Electric Service, **have authority to submit this report on the company's behalf. I further declare that the megawatt-hours claimed as specific purchases as shown in these Schedules were, to the best of my knowledge, sold once and only once to retail consumers.**

Name: **Joseph Phalen**

Signed: Joseph Phalen

Dated: 5/31/2018

4. A description of the treatment of disadvantaged communities, as required in Ordering Paragraph 6.

For purposes of integrated resource planning, a disadvantaged community shall be defined as any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, using the most recent version of the California Environmental Protection Agency's CalEnviroScreen tool. [50]

The table below confirms that BVES service area, which consists of Big Bear Lake, Big Bear City, and Fawnskin does not have a disadvantaged community as defined by the CalEnviro Screen tool below. [51]Note, Fawn skin is in census track 6071011300.

Census Tract	Total Population	California County	ZIP	Nearby City (to help approximate location only)	Longitude	Latitude	CES 3.0 Score	CES 3.0 Percentile	CES 3.0 Percentile Range	SB 535 Disadvantaged Communit
6071011203	1593	San Bernardino	92315	Big Bear Lake	-116.8823112	34.2507714	30.48	60.46	60-65%	No
6071011205	1239	San Bernardino	92315	Big Bear Lake	-116.9082131	34.2412057	30.32	60.07	60-65%	No
6071011300	1408	San Bernardino	92314	Big Bear City	-116.9502352	34.3019952	29.24	58.10	55-60%	No
6071011401	4394	San Bernardino	92314	Big Bear City	-116.8481795	34.2528568	27.97	55.85	55-60%	No
6071011206	995	San Bernardino	92315	Big Bear Lake	-116.9467039	34.2409525	21.44	41.93	40-45%	No
6071011404	3692	San Bernardino	92314	Big Bear City	-116.7540769	34.2724679	15.57	26.66	25-30%	No
6071011403	3350	San Bernardino	92314	Big Bear City	-116.8254603	34.2429726	13.68	21.63	20-25%	No
6071011102	2031	San Bernardino	92314	Big Bear City	-117.0878551	34.2553357	13.03	20.18	20-25%	No
6071011204	1271	San Bernardino	92314	Big Bear City	-116.8619415	34.2352744	11.74	16.85	15-20%	No

Ozone	Ozone Pctl	PM2.5	PM2.5 Pctl	Diesel PM	Diesel PM Pctl	Drinking Water	Drinking Water Pctl	Pesticides	Pesticides Pctl	Tox. Release
0.068	100.00	8.27876414	20.16	1.825	5.81	318.07	34.02	0.00	0.00	14.90809017
0.068	100.00	7.02122524	10.74	1.951	6.01	321.74	34.31	0.00	0.00	15.25706884
0.068	100.00	7.85958451	17.81	1.073	3.66	579.90	61.13	0.00	0.00	49.05554216
0.068	100.00	8.27876414	20.16	1.254	4.36	318.03	34.00	0.00	0.00	13.12780628
0.068	100.00	6.60204561	8.67	1.292	4.43	321.15	34.26	0.00	0.00	16.36939003
0.068	100.00	7.44040487	11.80	1.358	4.63	423.64	43.98	0.00	0.00	13.90994538
0.068	100.00	8.27876414	20.16	2.036	6.20	371.93	38.57	0.00	0.00	7.83445227
0.068	100.00	7.85958451	17.81	0.405	1.48	674.80	79.54	0.00	0.00	272.6646468
0.068	100.00	7.85958451	17.81	0.596	2.28	321.53	34.29	0.00	0.00	12.90547912

[50] See http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30 and https://calepa.ca.gov/wp-content/uploads/sites/62/2017/04/SB-535-Designation-Final.pdf.
[51] Fawnskin is located in census track 6071011300

Tox. Release Pctl	Traffic	Traffic Pctl	Cleanup Sites	Cleanup Sites Pctl	Groundwater Threats	Groundwater Threats Pctl	Haz. Waste	Haz. Waste Pctl	Imp. Water Bodies	Imp. Water Bodies Pctl
10.45	644.41	45.71	0.4	6.33	6	36.38	0.1	43.11	9	80.63
10.55	714.01	51.17	0	0.00	8	42.85	0.025	15.68	9	80.63
18.94	135.37	2.63	4	39.00	2	13.52	0	0.00	9	80.63
9.99	372.6	18.42	4	39.00	2	13.52	0	0.00	8	76.39
10.80	221.63	6.72	0	0.00	0	0.00	0	0.00	5	55.01
10.24	167.43	4.06	0	0.00	0	0.00	0	0.00	0	0.00
7.82	399.8	20.92	0	0.00	0	0.00	0	0.00	4	48.80
41.24	249.53	8.37	1	17.97	6	36.38	0	0.00	3	41.15
9.94	NA	NA	0	0.00	0	0.00	0	0.00	4	48.80

Solid Waste	Solid Waste Pctl	Pollution Burden	Pollution Burden Score	Pollution Burden Pctl	Asthma	Asthma Pctl	Low Birth Weight	Low Birth Weight Pctl	Cardiovascular Disease	Cardiovascular Disease Pctl
5.5	75.64	36.73	4.52	36.47	60.36	69.57	8.33	97.81	15.79	98.59
1.25	36.52	31.98	3.94	24.28	75.84	82.52	4.41	36.10	19.86	99.75
20.5	97.55	34.83	4.29	31.52	42.48	45.71	5.77	71.93	10.78	81.40
7	82.83	31.92	3.93	24.16	46.64	51.91	7.64	94.98	11.82	87.71
2	50.44	22.73	2.80	6.40	77.77	83.43	NA	NA	20.37	99.84
1	32.80	18.83	2.32	2.31	47.9	53.50	6.6	86.24	12.13	89.20
0	0.00	21.70	2.67	5.04	47.9	53.50	2.38	3.86	12.13	89.20
9.9	88.61	35.94	4.43	34.39	31.26	27.44	1.61	1.00	6.16	25.83
1.25	36.52	23.95	2.95	7.88	32.64	29.65	NA	NA	8.44	56.50

Education	Education Pctl	Linguistic Isolation	Linguistic Isolation Pctl	Poverty	Poverty Pctl	Unemployment	Unemployment Pctl	Housing Burden	Housing Burden Pctl	Pop. Char.
9.8	38.54	NA	NA	26.6	38.88	NA	NA	17.2	46.43	64.97
21.3	64.43	10.7	61.47	62	86.25	13.5	78.41	29.9	87.64	74.22
8.2	33.01	NA	NA	31.9	47.86	22.4	97.63	27.1	81.91	65.72
14.2	50.35	3.2	24.17	48.8	71.88	11.1	64.04	28.3	84.49	68.59
11.9	44.76	NA	NA	34.7	52.09	12.2	71.24	NA	NA	73.83
12.8	47.25	2.2	15.68	30.6	45.85	23.5	98.27	19.9	58.64	64.73
2.9	9.82	1.7	11.52	50.3	73.53	11.9	69.48	28.5	84.82	49.34
6.3	25.08	1.9	13.12	38.6	57.60	7.4	32.87	21.4	64.81	28.39
3.1	10.74	3	22.52	31.8	47.68	4.3	8.06	26	79.40	38.38

Pop. Char. Score	Pop. Char. Pctl
6.74	72.66
7.70	86.03
6.82	73.73
7.11	77.92
7.66	85.51
6.71	72.30
5.12	49.00
2.94	18.06
3.98	32.24

5. A description of how planned future procurement is consistent with the Greenhouse Gas Planning Price or its individual Greenhouse Gas Benchmark.

In D.18-02-018, the target of carbon emissions set for Bear Valley Electric Service is 0.027 MMT per year by 2030. In this Report, Table 22, "*Composition of Demand and Supply with Emissions Data*" provides the MMT of annual carbon emissions for 1) Imported Power; 2) Bear Valley Power Plant (BVPP) generation; 3) Total Bear Valley Electric Services; and 4) Mammoth Ski Resort reduction in emissions due to BVES sales to Snow Summit in place of Snow Summit diesel fueled generation.

BVES carbon emissions was 0.0362 MMT in 2015, 0.0273 MMT in 2016, 0.0202 MMT in 2017 , 0.0224 in 2018, and by 2028 emissions are anticipated to be reduced to 0.0101 MMT. BVES expects that in 2030 emissions will remain at or below 0.0101 MMT, which is well below the Commission 2030 target of 0.027 MMT of carbon emissions.

Table 22 of this Report also shows the total energy sales in column 5, and total energy requirement in column 10. BVES own solar production is shown in column 6 which will substitute import power resulting in zero GHG emissions. Also residential and commercial customers-owned solar generation, shown in Table 22, column 14, will reduce imported power supply, which results in lower GHG emissions. BVES energy efficiency program, which is mainly driven by lighting efficiency enhancements, shown in Table 22, column 15, has reduced the retail sales, and peak load requirement. As a result of the lower peak load requirement, BVES power plant does not generate power as often and thus reducing GHG emissions. Therefore, the combination of reduced retail sales and the increase of utility and customer-owned solar production will significantly reduce BVES GHG emissions.

The imported power carbon emissions per MWh of production should decline from 2018 to 2028, and through 2030. This is the result of the penetration of solar and wind generation in the utility portfolio and the continued growth in the customers DG solar and wind generation in the CAISO. Other states in the WECC regions will share in this trend. This is the result of tax incentives, reduced cost of solar panels, and California RPS goals. These changes lead to a reduction in the annual carbon emissions for BVES imported power from 0.0362 MMT in 2015 to 0.0101 MMT in 2028. [52]

It should be noted that the achieved emission reduction target also includes additional sales to the Big Bear Area Regional Wastewater Agency (BBARWA) and Snow Summit ski resort. The additional sales may substitute part of BBARWA generation with BVES imported power during the nighttime and with future BVES owned solar production

[52] This reduction is shown in Table 22, column 16.

during the daytime. The reduction of emissions is more defined for Snow Summit 2 ski resorts as the resorts will remove their diesel generators and rely on BVES system. As shown in Table 22, BVES supplemental sales to Snow Summit (also known as Mammoth) would reduce emissions by 0.0122 MMT per year, while supplemental sales to BBARWA would reduce carbon emissions by 0.0020 MMT per year.

Furthermore, BVES IRP fully accommodates the anticipated BVES-owned solar project of 8 MW and the expected customer-owned solar capacity of 9 MW by 2028. The intermittency of the customer produced solar contribution to the grid and the more defined utility owned solar production will be managed by the anticipated 5 MW/ 4 hour battery solution. This system will allow full utilization of the solar generation output and significant reduction of GHG emissions.

In addition, BVES power purchase agreements (PPA) with energy providers for firm power are shaped to the solar production and efficiency outlooks. The firm power PPAs will not only reduce price risk, and secure supply, but should also reduce GHG emissions. Candidates who recently bid for BVES PPAs have little to no emissions in their power supply portfolios. BVES anticipates this situation will continue in future request for proposals processes. IHS CERA provides BVES with the forecasted import power emissions assumptions, which are based on the optimization analysis of the CAISO energy supply. IHS CERA is a highly respected consulting firm that takes into account the demand and supply conditions for North America energy markets, along with policy impacts to derive optimal dispatch and the likely generation production outcomes. The fuel burn from the analytics along with the GHG emissions per unit of fuel for CAISO was used to determine emission amounts in MMT for BVES supply imports of power from the CAISO. The analysis confirmed the anticipated reduction in GHG emission intensity for BVES imported power.

BVES follows the analytical steps noted above to ensure that its procurement plan would achieve the GHG targets set in D.18-02-018.

6. Conforming Portfolio, consistent with the Reference System Portfolio.

BVES describes in the next section its own alternative system portfolio along with identification and justification for any deviations in assumptions from the Commission Reference System Portfolio

7. A description of any alternative or preferred portfolio along with identification and justification for any deviations in assumptions from the Reference System Portfolio

BVES utilizes a different set of assumptions to establish its energy portfolio than those underlying the Reference System Portfolio.

BVES assumptions are based on the IHS CERA May 2018 Rivalry Study. Results of this IHS CERA study are consistent with other national, state, market areas studies and studies of fuel price dynamics as well as studies about the dynamics of fuel prices. BVES uses these results to design its IRP to achieve the GHG and RPS goals with the most cost effective solutions for its customers.

BVES' IRP study is consistent with the Commission System Reference Portfolio albeit with slight insignificant differences. Some of the differences are: 1) BVES peak load timing is different than the rest of California market as a whole; and 2) IHS CERA view of the California market outcome is slightly different than the Commission System Reference Portfolio study. Overall the two studies are consistent.

<u>BVES Imported Power Supply</u>

BVES provides below a set of tables that shows its energy requirements for the next 10 years. BVES energy requirements by year are as follows:

- Table 24 provides the amount of each supply component, in MWh, that meets BVES energy requirements;
- Table 25 provides the percentage of each supply component that meets BVES energy requirement;
- Table 26 shows the aggregated percentage of each supply component to compare with the Commission Reference System Portfolio, which is shown in Table 31 below. BVES service territory is a destination for ski sports and for summer tourism located in the middle of protected state forest lands, the availability of land for power generation projects is limited. Therefore a large portion of power supply is imported. BVES target for energy imports is about 68% by 2030. This differs from the percent allocation of 3.9% established by the Commission for California in 2030.
- Table 27 shows the generation by type in the California market. IHS CERA provides the estimates for the various types of generation in the California market.

- Table 28 shows the generation by type and by percentage share in the California market. BVES uses these percentage shares to determine the fuel content of its own imported power.
- Table 29 provides the fuel content of BVES imported energy supply. Assuming that both the imported energy and the California energy market have the same content, BVES fuel content is derived from the shares of each of type of power generation in the California energy market.
- BVES anticipates that the share of Energy Efficiency and that of Renewables will increase as a percentage of BVES imported power supply, and thus meeting the level of energy requirements noted in the Commission Reference System Portfolio and reported in Table 31
- Table 30 is the energy requirement by fuel type in percentage terms for BVES imported supply only. This table is most comparable to Table 31 for the reference case although BVES imports are significantly greater than the Reference System Portfolio assumptions; and because of BVES geographical characteristics and small customer base gas fueled generation is considerably smaller than the reference portfolio.

Table 24: BVES Supply Meeting Energy Requirements (MWh)

	Energy Efficiency	Customer DG Solar	Utility owned Solar	Gas Fired Gen BVPP	Interruption of Sales	Imported CAISO Power	Line Losses	Total Energy Required for IRP Planning
2018	3,130	8,039	0	1	0	152,017	16,288	179,474
2019	4,795	9,529	0	76	0	158,855	14,189	187,443
2020	6,451	10,923	19,769	144	0	151,863	16,171	205,321
2021	7,915	12,330	19,631	136	0	150,500	16,010	206,522
2022	9,690	13,604	19,493	128	0	149,592	15,897	208,404
2023	11,472	14,727	19,357	126	0	149,220	15,842	210,744
2024	12,775	15,756	19,221	126	0	149,459	15,853	213,190
2025	14,066	16,671	19,087	279	0	149,196	15,936	215,235
2026	15,234	17,433	18,953	279	0	148,707	15,831	216,437
2027	16,065	18,110	18,820	272	0	148,323	15,775	217,364
2028	16,510	18,699	18,689	288	0	148,794	16,582	219,562

Table 25: BVES Supply of Energy Requirements in Percent

	Energy Efficiency	Customer DG Solar	Utility owned Solar	Gas Fired Gen BVPP	Interruption of Sales	Imported CAISO Power	Line Losses	Total Energy Required for IRP Planning
2018	1.74%	4.48%	0.00%	0.00%	0.00%	84.70%	9.08%	100.00%
2019	2.56%	5.08%	0.00%	0.04%	0.00%	84.75%	7.57%	100.00%
2020	3.14%	5.32%	9.63%	0.07%	0.00%	73.96%	7.88%	100.00%
2021	3.83%	5.97%	9.51%	0.07%	0.00%	72.87%	7.75%	100.00%
2022	4.65%	6.53%	9.35%	0.06%	0.00%	71.78%	7.63%	100.00%
2023	5.44%	6.99%	9.18%	0.06%	0.00%	70.81%	7.52%	100.00%
2024	5.99%	7.39%	9.02%	0.06%	0.00%	70.11%	7.44%	100.00%
2025	6.54%	7.75%	8.87%	0.13%	0.00%	69.32%	7.40%	100.00%
2026	7.04%	8.05%	8.76%	0.13%	0.00%	68.71%	7.31%	100.00%
2027	7.39%	8.33%	8.66%	0.13%	0.00%	68.24%	7.26%	100.00%
2028	7.52%	8.52%	8.51%	0.13%	0.00%	67.77%	7.55%	100.00%

Table 26: BVES Supply of Energy Requirements Aggregated in Percent

	Energy Efficiency	Renewables	Gas Fired Gen BVPP	Imported CAISO Power	Line Losses	Total Energy Required for IRP Planning
2018	1.74%	4.48%	0.00%	84.70%	9.08%	100.00%
2019	2.56%	5.08%	0.04%	84.75%	7.57%	100.00%
2020	3.14%	14.95%	0.07%	73.96%	7.88%	100.00%
2021	3.83%	15.48%	0.07%	72.87%	7.75%	100.00%
2022	4.65%	15.88%	0.06%	71.78%	7.63%	100.00%
2023	5.44%	16.17%	0.06%	70.81%	7.52%	100.00%
2024	5.99%	16.41%	0.06%	70.11%	7.44%	100.00%
2025	6.54%	16.61%	0.13%	69.32%	7.40%	100.00%
2026	7.04%	16.81%	0.13%	68.71%	7.31%	100.00%
2027	7.39%	16.99%	0.13%	68.24%	7.26%	100.00%
2028	7.52%	17.03%	0.13%	67.77%	7.55%	100.00%

Table 27: CA Generation in GWh by Type; BVES Assumption for Imported Power Content

CA Gen by Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas CC	75,420	73,319	68,956	63,735	58,995	57,733	57,378	63,991	68,402	68,831	69,052
Gas CT	10,852	10,984	11,088	11,363	11,599	11,677	12,109	12,475	12,675	12,785	13,000
Gas ST	1,530	1,251	1,217	420	536	678	751	933	1,046	919	957
Coal–advanced	0	0	0	0	0	0	0	0	0	0	0
Coal–conventional	0	0	0	0	0	0	0	0	0	0	0
Nuclear	18,661	18,118	17,696	18,295	18,074	16,708	16,628	5,289	0	0	0
Hydro	31,238	29,370	29,389	29,420	29,445	29,477	29,532	29,578	29,618	29,670	29,723
Oil	0	0	0	0	0	0	0	0	0	0	0
Wind	14,886	15,525	19,572	22,868	26,007	29,283	29,475	29,712	30,214	30,646	31,072
Solar PV	40,522	46,867	53,083	58,669	64,050	67,881	68,346	70,035	71,106	71,551	71,863
Solar CSP	5,203	5,201	5,210	5,195	5,185	5,178	5,181	5,180	5,180	5,180	5,188
Biomass	5,580	5,683	5,773	5,805	5,832	5,861	5,942	6,095	6,230	6,334	6,447
Geothermal	16,604	16,647	16,850	16,791	16,359	16,322	16,570	16,827	17,291	17,283	17,675
Pumped storage	(1,336)	(1,424)	(1,470)	(1,445)	(1,439)	(1,444)	(1,385)	(1,480)	(1,516)	(1,510)	(1,509)
Batteries (≥ 4 hour duration)	(30)	(62)	(98)	(133)	(164)	(196)	(220)	(264)	(307)	(343)	(368)
Total generation (GWh)	219,128	221,479	227,266	230,984	234,478	239,158	240,307	238,371	239,939	241,346	243,099

Table 28: California Generation by Fuel Type in Percent

CA Gen by Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas CC	34.42%	33.10%	30.34%	27.59%	25.16%	24.14%	23.88%	26.85%	28.51%	28.52%	28.40%
Gas CT	4.95%	4.96%	4.88%	4.92%	4.95%	4.88%	5.04%	5.23%	5.28%	5.30%	5.35%
Gas ST	0.70%	0.56%	0.54%	0.18%	0.23%	0.28%	0.31%	0.39%	0.44%	0.38%	0.39%
Coal–advanced	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Coal–conventional	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	8.52%	8.18%	7.79%	7.92%	7.71%	6.99%	6.92%	2.22%	0.00%	0.00%	0.00%
Hydro	14.26%	13.26%	12.93%	12.74%	12.56%	12.33%	12.29%	12.41%	12.34%	12.29%	12.23%
Oil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wind	6.79%	7.01%	8.61%	9.90%	11.09%	12.24%	12.27%	12.46%	12.59%	12.70%	12.78%
Solar PV	18.49%	21.16%	23.36%	25.40%	27.32%	28.38%	28.44%	29.38%	29.64%	29.65%	29.56%
Solar CSP	2.37%	2.35%	2.29%	2.25%	2.21%	2.17%	2.16%	2.17%	2.16%	2.15%	2.13%
Biomass	2.55%	2.57%	2.54%	2.51%	2.49%	2.45%	2.47%	2.56%	2.60%	2.62%	2.65%
Geothermal	7.58%	7.52%	7.41%	7.27%	6.98%	6.82%	6.90%	7.06%	7.21%	7.16%	7.27%
Pumped storage	-0.61%	-0.64%	-0.65%	-0.63%	-0.61%	-0.60%	-0.58%	-0.62%	-0.63%	-0.63%	-0.62%
Batteries (≥ 4 hour duration)	-0.01%	-0.03%	-0.04%	-0.06%	-0.07%	-0.08%	-0.09%	-0.11%	-0.13%	-0.14%	-0.15%
Total generation (GWh)	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 29: BVES Energy Composition Assuming Imported Power Content Equals to California Generation Mix

Year	Energy Efficiency	Renewables	Gas Fired Gen	Hydro	Nuclear	Line Losses	Total Energy Required for IRP Planning
2018	1.7%	36.0%	33.9%	12.1%	7.2%	9.1%	100.0%
2019	2.6%	38.9%	32.8%	11.2%	6.9%	7.6%	100.0%
2020	3.1%	47.1%	26.5%	9.6%	5.8%	7.9%	100.0%
2021	3.8%	49.5%	23.9%	9.3%	5.8%	7.8%	100.0%
2022	4.6%	51.3%	21.8%	9.0%	5.5%	7.6%	100.0%
2023	5.4%	52.6%	20.8%	8.7%	4.9%	7.5%	100.0%
2024	6.0%	52.6%	20.5%	8.6%	4.9%	7.4%	100.0%
2025	6.5%	53.3%	22.6%	8.6%	1.5%	7.4%	100.0%
2026	7.0%	53.5%	23.6%	8.5%	0.0%	7.3%	100.0%
2027	7.4%	53.5%	23.5%	8.4%	0.0%	7.3%	100.0%
2028	7.5%	53.4%	23.3%	8.3%	0.0%	7.6%	100.0%

Table 30: BVES Energy Requirement from Local Supply Only Composition

Year	Energy Efficiency	Renewables	Gas Fired Gen BVPP	Total Energy Required for IRP Planning
2018	28.0%	72.0%	0.0%	100.0%
2019	33.3%	66.2%	0.5%	100.0%
2020	17.3%	82.3%	0.4%	100.0%
2021	19.8%	79.9%	0.3%	100.0%
2022	22.6%	77.1%	0.3%	100.0%
2023	25.1%	74.6%	0.3%	100.0%
2024	26.7%	73.1%	0.3%	100.0%
2025	28.1%	71.4%	0.6%	100.0%
2026	29.4%	70.1%	0.5%	100.0%
2027	30.2%	69.3%	0.5%	100.0%
2028	30.5%	69.0%	0.5%	100.0%

Table 31: Proportion of Gross Energy Generation in Reference System Portfolio in 2030

Resource	Percentage of Gross GWh
Renewables	44.9%
Gas	23.4%
Energy Efficiency	11.7%
Hydro	9.0%
CHP	5.3%
Net Imports	3.9%
Nuclear	1.8%

BVES GHG Emissions

BVES IRP meets the reduction in GHG emissions target of 0.027 MMT set for BVES for 2030. [53]

BVES describes below two approaches for measuring GHG emissions. One is the emissions intensity measure, which is determined by the amount MMT per unit of electricity in GWh. The other approach is to ensure that all BVES's power purchase agreements include zero emission clause.

Emissions Intensity Measure

- Table 32 shows the amount of GHG emissions from natural gas fueled power generation in the California market.
- The last three rows in Table 32 shows
    - Total California: The total California GHG emission in MMT
    - Calibrated Emissions: It is the total California emissions adjusted to BVES 2004 amount of imported power supply in MMT. In other words, BVES calibrates or adjusts the estimated GHG emissions to reflect BVES the content of its imported power.
    - CA CO_2 Emissions (MMT/GWh): This is the amount of California emissions imported by BVES per unit of energy. It is a measure of emissions intensity.

The emissions intensity values reported in Table 32 show that in 2018 it is 0.00023 MMT per GWh, and by 20128 it is estimated to be 0.00020 MMT per GWh. Given that BVES does not generate energy to procure for its baseload demand, and given that its energy imports are more than 65 percent of its energy requirement, these values denote how small the amount of emissions is relative to the amount of energy that BVES imports from the California market.

[53] D.18-02-018, Table 7, p. 125

Table 32: California Carbon Emissions and Intensity

CA Emissions (MMT) by Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas CC	29.5	28.5	26.6	24.6	22.7	22.2	22.0	24.5	26.2	26.3	26.3
Gas CT	6.0	6.1	6.1	6.3	6.4	6.4	6.7	6.8	6.9	7.0	7.1
Gas ST	0.8	0.7	0.7	0.2	0.3	0.4	0.4	0.5	0.6	0.5	0.5
Coal–advanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal–conventional	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar CSP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total California	36	35	33	31	29	29	29	32	34	34	34
Calibrated Emissions	50.83	49.33	46.78	43.49	41.15	40.58	40.72	44.63	47.17	47.32	47.56
CA CO2 Emissions MMT/GWH	**0.00023**	**0.00022**	**0.00021**	**0.00019**	**0.00018**	**0.00017**	**0.00017**	**0.00019**	**0.00020**	**0.00020**	**0.00020**

Zero Emission Clause for Power Purchase Agreements

BVES requires that energy marketers who bid on BVES request for proposals to provide baseload and seasonal energy must do their best to comply with the zero emission content.

Table 33 below provides GHG emissions with the scenario that power purchase agreements (PPA) for energy have zero emission. As shown in Table 33, column 4, the current total emissions come primarily from BVES energy import from the California market or the CAISO. In 2018, total emissions are 0.02236 MMT. In 2028, total emissions are anticipated to be 0.01008 MMT. During the 10-year period, total emissions are below the BVES target emissions of 0.027 MMT.

The inclusion of PPAs with zero emission or almost zero content, as shown in Table 33, column 6, does not add much to the total emissions measured over the 10-year period

Table 33: Carbon Emissions (MMT) for Bear Valley Electric, Included Import Power Content Scenario

Year	Bear Valley Power Plant (1)	Renewables (2)	Imported Power from CA Market (3)	Total Emissions (4)= (1)+(2)+(3)	Imported 0 Emissions Power Alternative (5)	Total Emissions with 0 Emissions Imported Power (6)	GHG Emissions 2030 Target for BVES (7)
2018	0.00000	0.00000	0.02236	0.02236	0.00000	0.00000	0.027
2019	0.00003	0.00000	0.02099	0.02102	0.00000	0.00003	0.027
2020	0.00006	0.00000	0.01453	0.01459	0.00000	0.00006	0.027
2021	0.00005	0.00000	0.01272	0.01277	0.00000	0.00005	0.027
2022	0.00005	0.00000	0.01138	0.01143	0.00000	0.00005	0.027
2023	0.00005	0.00000	0.01059	0.01064	0.00000	0.00005	0.027
2024	0.00005	0.00000	0.01023	0.01028	0.00000	0.00005	0.027
2025	0.00011	0.00000	0.01087	0.01098	0.00000	0.00011	0.027
2026	0.00011	0.00000	0.01094	0.01105	0.00000	0.00011	0.027
2027	0.00010	0.00000	0.01045	0.01056	0.00000	0.00010	0.027
2028	0.00011	0.00000	0.00997	0.01008	0.00000	0.00011	0.027

BVES Installed Capacity

BVES installed capacity portfolio is in line with the Commission recommended system portfolio as shown in Table 37. Table 34 and Table 35 show BVES installed capacity in MW and percentage, respectively. Table 36 shows BVES installed local capacity.

BVES IRP proposes the following:

- A significant increase in customer and utility owned generation.
- No growth is anticipated for the capacity of BVES gas fired generation, the Bear Valley Power Plant (BVPP).
- An increase in the amount of interruptible capacity to serve BVES largest customer, the area 2 ski resorts. The interruptible load will allow supplemental sales to the ski resorts without adding capacity to the current capacity utilization.
- The construction of storage battery to
    - Allow BVES to meet additional load beyond existing capacity. The 5 MW battery discharge will increase BVES ability to serve the peak load and the charge of the battery during the daytime hours will increase the load served during the solar production hours. BVES peak occurs during the hours of 7 PM to 10 PM, and the minimum load occurs during the daytime hours between noon and 5 pm.
    - Allow BVES to shift a portion of the supply from customer-owned and utility-owned solar generation to the peak hours through the battery duty cycle.
    - Allow BVES to increase the installed capacity provided by the battery, which will: i) accommodate the percentage of renewables in BVES portfolio; ii) support the peak load; iii) reduce BVES energy supply cost as a result of an increase in solar energy production; and iv) allow BVES to be in line with the Commission recommended system portfolio shown in Table 37.

Table 34: BVES Installed Capacity in MW

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Imported CAISO Power	Battery	Shed Demand Response	Total Capacity
2018	0.86	4.2		8.4	39		15.0	67.43
2019	1.31	4.9		8.4	39		15.0	68.66
2020	1.77	5.7	8.0	8.4	39	5.0	28.0	95.84
2021	2.17	6.4	8.0	8.4	39	5.0	28.0	96.97
2022	2.65	7.1	8.0	8.4	39	5.0	28.0	98.11
2023	3.14	7.6	8.0	8.4	39	5.0	28.0	99.18
2024	3.50	8.2	8.0	8.4	39	5.0	28.0	100.08
2025	3.85	8.7	8.0	8.4	39	5.0	28.0	100.90
2026	4.17	9.0	8.0	8.4	39	5.0	28.0	101.62
2027	4.40	9.4	8.0	8.4	39	5.0	28.0	102.20
2028	4.52	9.7	8.0	8.4	39	5.0	28.0	102.63

Table 35: BVES Installed Capacity in Percent

Year	Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Imported CAISO Power	Battery	Shed Demand Response	Total Capacity
2018	1.27%	6.19%	0.00%	12.46%	57.84%	0.00%	22.25%	100.00%
2019	1.91%	7.20%	0.00%	12.23%	56.80%	0.00%	21.85%	100.00%
2020	1.84%	5.91%	8.35%	8.77%	40.69%	5.22%	29.22%	100.00%
2021	2.24%	6.60%	8.25%	8.66%	40.22%	5.16%	28.88%	100.00%
2022	2.71%	7.19%	8.15%	8.56%	39.75%	5.10%	28.54%	100.00%
2023	3.17%	7.70%	8.07%	8.47%	39.32%	5.04%	28.23%	100.00%
2024	3.50%	8.17%	7.99%	8.39%	38.97%	5.00%	27.98%	100.00%
2025	3.82%	8.57%	7.93%	8.32%	38.65%	4.96%	27.75%	100.00%
2026	4.11%	8.90%	7.87%	8.27%	38.38%	4.92%	27.55%	100.00%
2027	4.31%	9.19%	7.83%	8.22%	38.16%	4.89%	27.40%	100.00%
2028	4.41%	9.45%	7.80%	8.19%	38.00%	4.87%	27.28%	100.00%

Table 36: BVES Installed Local Capacity in Percent

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Battery	Shed Demand Response	Total Capacity
2018	3.02%	14.67%	0.00%	29.55%	0.00%	52.76%	100.00%
2019	4.43%	16.67%	0.00%	28.32%	0.00%	50.58%	100.00%
2020	3.11%	9.97%	14.08%	14.78%	8.80%	49.27%	100.00%
2021	3.74%	11.04%	13.80%	14.49%	8.63%	48.30%	100.00%
2022	4.49%	11.94%	13.53%	14.21%	8.46%	47.37%	100.00%
2023	5.22%	12.70%	13.29%	13.96%	8.31%	46.52%	100.00%
2024	5.73%	13.39%	13.10%	13.75%	8.19%	45.84%	100.00%
2025	6.23%	13.97%	12.92%	13.57%	8.08%	45.23%	100.00%
2026	6.67%	14.45%	12.78%	13.41%	7.98%	44.71%	100.00%
2027	6.96%	14.87%	12.66%	13.29%	7.91%	44.30%	100.00%
2028	7.11%	15.25%	12.57%	13.20%	7.86%	44.01%	100.00%

Table 37: Recommended System Portfolio for California in 2030

Resource	MW (% total)
Natural Gas	25.9
Solar	21.7
Customer Solar	16.0
Wind	9.3
Hydro (Large)	7.9
Energy Efficiency	7.4
Battery Storage	3.3
Pumped Storage	1.8
Shed Demand Response	1.8
CHP	1.7
Geothermal	1.4
Biomass	0.7
Nuclear	0.6
Hydro (Small)	0.5

The major difference between BVES and the California energy system as a whole is the timing of the peak load. BVES load peaks between 7 PM to 10 PM, while the California system peaks between 3:30 PM to 6 PM. This situation creates a significant difference between peak load serving capacity and installed capacity for BVES. All of BVES solar capacity is reduced to zero during the peak hours, which are during the night time. Therefore, the installed capacity for BVES is more comparable to the California energy market than the BVES installed capacity available to BVES at peak hours. Table 38 below shows BVES installed capacity available at peak hours.

The timing difference in the peak load allows BVES: 1) to import more abundant power at lower cost from the California market during off peak hours; and 2) during the peak period for California system, BVES abundant capacity in solar production is used to shave the energy requirements from other sources.

Table 38: BVES Installed Capacity Available at BVES Peak in Percent

Year	Energy Efficiency	Customer Owned Solar	Utility owned Solar	Gas Fired Gen BVPP	Imported CAISO Power	Battery	Shed Demand Response	Total Capacity
2018	1.50%	0.00%	0.00%	14.67%	68.11%	0.00%	15.72%	100.00%
2019	1.97%	0.00%	0.00%	12.57%	58.37%	0.00%	27.09%	100.00%
2020	2.45%	0.00%	0.00%	11.62%	53.97%	6.92%	25.05%	100.00%
2021	2.99%	0.00%	0.00%	11.58%	53.74%	6.89%	24.80%	100.00%
2022	3.63%	0.00%	0.00%	11.50%	53.38%	6.84%	24.64%	100.00%
2023	4.27%	0.00%	0.00%	11.42%	53.03%	6.80%	24.48%	100.00%
2024	4.74%	0.00%	0.00%	11.37%	52.77%	6.77%	24.36%	100.00%
2025	5.19%	0.00%	0.00%	11.31%	52.52%	6.73%	24.24%	100.00%
2026	5.60%	0.00%	0.00%	11.26%	52.30%	6.70%	24.14%	100.00%
2027	5.88%	0.00%	0.00%	11.23%	52.14%	6.68%	24.06%	100.00%
2028	6.04%	0.00%	0.00%	11.21%	52.05%	6.67%	24.02%	100.00%

Summary of BVES IRP Alternative Plan

In general, in its IRP BVES assumes that the California Energy Balance, shown in Figure 21 below, is consistent with the California System Reference Portfolio, shown in Figure 20 below. More specific, the Commission and BVES assume that: i) Energy Efficiency will slowly displace energy sales and supply requirement for California; ii) Renewable energy continues to expand within the reference portfolio; iii) support for nuclear power is reduced significantly; and hydroelectric power remains at the same level.

In this IRP BVES assumes that there is a small amount of coal and oil generation in the California power supply mix which drops out by 2025, while the Commission study does not mention any of these two fuels.

Figure 20: Total California Balance in Reference System Portfolio

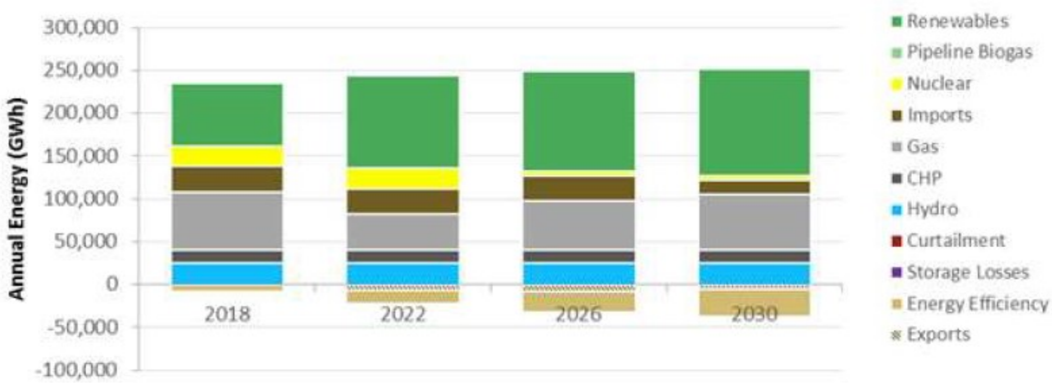
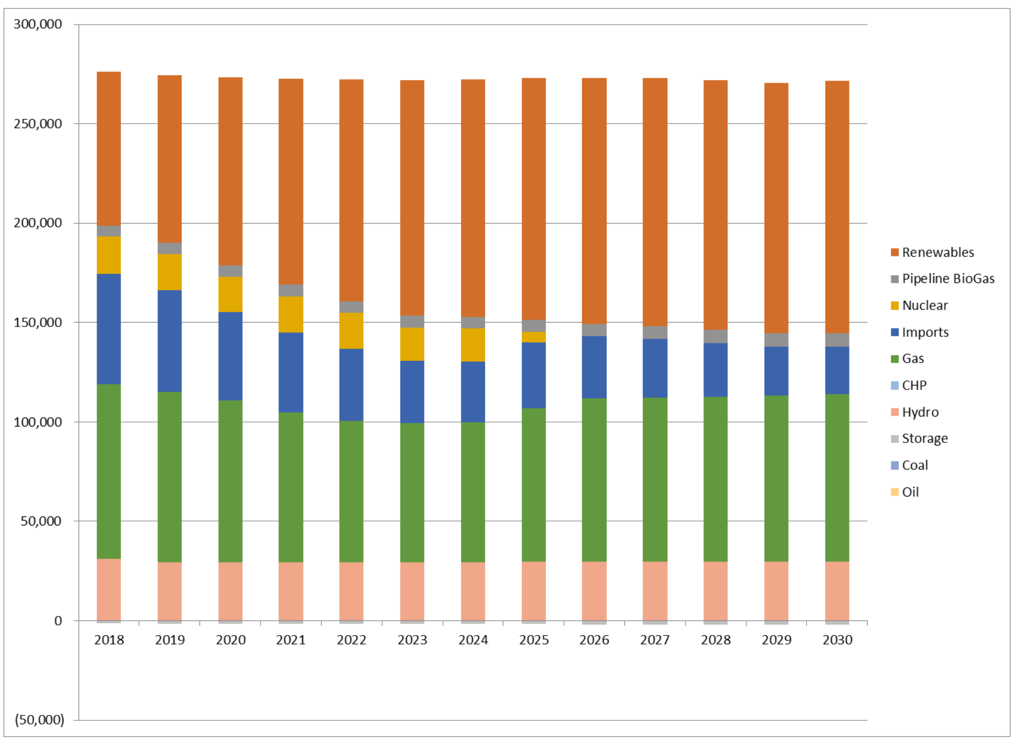


Figure 21: California Energy Balance Assumed in BVES IRP (Net Efficiency Impact) in GWh



8. A description of how the LSE's preferred portfolio is consistent with each relevant statutory and administrative requirement.

In this 2018-2028 IRP BVES describes its own preferred portfolio and BVES also shows that the portfolio is consistent with the relevant statutory and administrative requirement.

In this IRP BVES provides the description of the content of its portfolio and the content associated issues. BVES provides the following description:

- Renewable Resources, Renewable Program Standard, and Net Energy Metering, pp. 59-65
- Resource Adequacy, pp. 68-73.
- Energy Efficiency, Demand Response, and Time of Use Rates, pp. 73-79pp.
- Greenhouse Gas Emissions plan and how BVES emissions are compared with the Commission established target for BVES, pp. 84-87.

In addition, BVES provides in its IRP Alternative Plan a description of: i) BVES future procurement to achieve the Greenhouse Gas target established in D.18-02-018; and ii) BVES preferred portfolio is comparable with the Reference System Portfolio.

9. An action plan that includes all of the actions the LSE proposes to take in the next one to three years to implement its plan.

BVES action plan to meet the targets proposed in this IRP is as follows.

1. **Secure firm power contracts**
   - On May 2018 BVES sent out requests for proposals to over 100 power marketers for baseload and seasonal power contracts that conform to BVES hourly needs and zero emission requirement specified in this IRP.
   - BVES is reviewing the bids received and the credit quality of the bidders to determine short list of bidders for the final round.
   - BVES will file an application with the Commission for approval of the contracts and the benchmark price.

2. **Secure 8 MW solar project**.
   - BVES has signed a Memorandum of Understanding with Bid Bear Area Regional Wastewater Agency (BBARWA) and the project builder;
   - The 8 MW solar project is an 8 MW single axis tracking system that will be built on a dry lake;
   - BVES has begun the Phase 1 permitting process for the solar facility;
   - BVES will file shortly an application with the Commission to request approval for the project.

2. **Expand capacity of substation for BVES largest customer**
   - BVES largest customer, the two ski resorts, wants to retire its diesel fueled power generation.
   - The upgrade of the substation is requested in BVES current General Rate Case application.

3. **Transportation Electrification Pilot Program**
   - BVES is waiting for the Commission decision on this program

4. **Lighting Energy Efficiency Program**
   - BVES anticipates to revisit the energy efficiency program to include BVES customers.

5. **Energy Storage Battery**
   - BVES anticipates the retention of an outside consultant to study BVES battery needs and to draft request for proposals

10. A description of any barriers and lessons learned from the prior IRP and/or procurement.

A lesson learned from the prior IRP and power procurement is that the bidder selection process has been more diligent on the contract guarantees and on the bidder credit ratings. This process is as important as the evaluation of the price bids for the 36 months contracts and 59 months contracts.

EIA FORM 861

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by May 16th following the close of calendar year

Contact Nguyen Quan
Title: Manager Regulatory Affairs

Phone: (909) 394-3600 Ext. 664 FAX: (909) 394-7427 Email: nquan@gswater.com

REPORT FOR: Bear Valley Electric Service 17612
REPORTING PERIOD: 2017

Supervisor Keith Switzer
Title: V.P. Regulatory Affair

Phone: (909) 394-3600 Ext. 759 FAX: (909) 394-7427 Email: kswitzer@gswater.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	Bear Valley Electric Service **Submission Status/Date:** Submitted 04/11/2018
2	Current Address of Principal Business Office	630 East Foothill Blvd. San Dimas CA 91773
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator ☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

ANNUAL ELECTRIC POWER INDUSTRY REPORT

Form Approved
OMB No. 1905-0129
Approved Expires 03/31/2020

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT); [ ] FRCC; [ ] MRO; [ ] NPCC; [ ] RFC (formerly ECAR, MAIN. MAAC); [ ] SERC; [ ] SPP; [x] WECC
2	Name of RTO or ISO	[X] California ISO; [ ] Electric Reliability Council of Texas; [ ] PJM Interconnection; [ ] New York ISO; [ ] Southwest Power Pool; [ ] Midwest ISO; [ ] ISO New England; [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	WECC
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant; [ ] Transmission; [x] Buying transmission services on other electrical system; [x] Distribution using owned/leased electric wires; [x] Buying distribution on other electrical system; [x] Wholesale power marketing; [ ] Retail power marketing; [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 25.5, Prior Year 24.9; Winter (Megawatts) 40.5, Prior Year 38.1
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[ ] Yes [x] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No
	If "Yes", Please Provide Additional Contact Information	Name: Joseph Phalen; Title: Manager; Telephone: 909 - 866 - 4678; Fax: - -; Email: joseph.phalen@bves.com

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	254	11	Sales to Ultimate Consumers	127,219
2	Purchases from Electricity Suppliers	148,018	12	Sales For Resale	
3	Exchanged Received (In)	7,343	13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)	7,821	14	Energy Consumed By Respondent Without Charge	574
5	Exchanged Net	-478			
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)		15	Total Energy Losses (positive number)	20,001
8	Wheeled Net				
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	147,794	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	147,794

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	**$**	33,948.7
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	**$**	
3	Electric Operating Revenue from Sales for Resale	**$**	
4	Electric Credits/Other Adjustments	**$**	
5	Revenue from Transmission	**$**	
6	Other Electric Operating Revenue	**$**	149.7
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	**$**	34,098.4

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **CA**

1	Total Number of Distribution Circuits	23.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State	CA
3a.	SAIDI value including Major Event days		80.054
3b.	SAIDI value excluding Major Event days		34.740
4	SAIDI value including Major Event days minus loss of supply		80.054
5a.	SAIFI value including Major Event days		1.086
5b.	SAIFI value excluding Major Event days		0.600
6.	SAIFI value including Major Event days minus loss of supply		1.086
7.	Total number of customers used in these calculations		23,975.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		34.5
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[ ] Yes	[x] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

REPORT FOR: Bear Valley Electric Service 17612

REPORT PERIOD ENDING: 2017

SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State CA **Balancing Authority**	2775				
Revenue (thousand dollars)	20,969.5	9,787.6	3,191.6	0.0	33,948.7
Megawatthours	75,681	35,658	15,880	0	127,219
Number of Customers	22,470	1,504	7	0	23,981
Are your rates decoupled?	x Yes No	x Yes No	x Yes No	x Yes No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	N automatic	N automatic	N automatic	N automatic	
	N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh	27.708	27.449	20.098		26.685
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					

Total					
Revenue (thousand dollars)	20,969.5	9,787.6	3,191.6	0.0	33,948.7
Megawatthours	75,681	35,658	15,880	0	127,219
Number of Customers	22,470	1,504	7	0	23,981

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SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State CA **Balancing Authority** 2775					
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total					
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0

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SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State CA **Balancing Authority** 2775					
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0
Cents/Kwh					

State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total					
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0

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SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State TX **Balancing Authority**	5723				
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0
Cents/Kwh					

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)	0.0	0.0	0.0	0.0	0.0
Megawatthours	0	0	0	0	0
Number of Customers	0	0	0	0	0

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SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS
Adjusted Gross Energy and Demand Savings -- Energy Efficiency

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **CA** **Balancing Authority** **2775**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	37.350	467.970	0.000	0.000	505.320
2	Peak Demand Savings (MW)	0.010	0.084	0.000	0.000	0.094
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	484.150	3,252.410	0.000	0.000	3,736.560
4	Peake Demand Savings (MW)	0.010	0.084	0.000	0.000	0.094
	Reporting Year Incremental Costs					
5	Customer Incentives	80.377	139.163	0.000	0.000	219.540
6	All other costs	31.165	7.124	0.000	0.000	38.289
	Incremental Life Sycle Costs					
7	Customer Incentives	80.377	139.163	0.000	0.000	219.540
8	All other costs	31.165	7.124	0.000	0.000	38.289
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	12.900	6.950	0.000	0.000	20.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **CA** **Balancing Authority** **2775**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	0	0	0	0	0
2	Energy Savings (Mwh)	0.000	0.000	0.000	0.000	0.000
3	Potential Peak Demand Savings (MW)	0.000	0.000	0.000	0.000	0.000
4	Actual Peak Demand Savings (MW)	0.000	0.000	0.000	0.000	0.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
5	Customer Incentives	0.000	0.000	0.000	0.000	0.000
6	All other costs	0.000	0.000	0.000	0.000	0.000

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **CA** **Balancing Authority** **2775**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	0	0	0	0	0

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No
3	Real-Time Pricing	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No
4	Variable Peak Pricing	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No
5	Critical Peak Pricing	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No
6	Critical Peak Rebate	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No	x Yes ☐ No

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **CA** **Balancing Authority** **2775**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	22,857	1,566	0	0	24,423
2	Number of AMI Meters	0	0	0	0	0
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	0	1	7	0	8
5	Total Number of Meters (All Types), line 1+2+4	22,857	1,567	7	0	24,431
6	Energy Served Through AMI	0	0	0	0	0
7	Number of Customers able to access daily energy usage through a webportal or other electronic means	0	0	0	0	0
8	Number of customers with direct load control	0	0	0	0	0

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State CA **Balancing Authority** 2775		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photovoltaic	Net Metering Installed Capacity (MW)	1.779	1.348	0.000	0.000	3.127
	Net Metering Installations	406	19	0	0	425
	Storage Installed Capacity (MW)	0.000	0.000	0.000	0.000	0.000
	Storage Installations	0	0	0	0	0
	Virtual NM Installed Capacity (1 MW and greater)	0.000	0.000	0.000	0.000	0.000
	Virtual NM Customers (1 MW and greater)	0	0	0	0	0
	Virtual NM Installed Capacity (less than 1MW)	0.000	0.000	0.000	0.000	0.000
	Virtual NM Customers (less than 1MW)	0	0	0	0	0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000	0.000	0.000	0.000
Wind	Installed Net Metering Capacity (MW)	0.048	0.010	0.000	0.000	0.058
	Number of Net Metering Customers	6	1	0	0	7
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000	0.000	0.000	0.000
Other	Installed Net Metering Capacity (MW)	0.000	0.000	0.000	0.000	0.000
	Number of Net Metering Customers	0	0	0	0	0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000	0.000	0.000	0.000
Total	Installed Net Metering Capacity (MW)	1.827	1.358	0.000	0.000	3.185
	Number of Net Metering Customers	412	20	0	0	432
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000	0.000	0.000	0.000
Grand Total All States	**Net Metering Installed Capacity (MW)**	1.827	1.358	0	0	3.185
	Net Metering Installations/customers	412	20	0	0	432
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0	0	0	0	0

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SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State CA **Balancing Authority** 2775 < 1MW

1. Number of generators	0	3. Capacity that consists of backup-only units	0.000
2. Total combined capacity (MW)	0.000	4. Capacity owned by respondent	0.000

Capacity by Technology and Sector (MW)

	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
5. Internal combustion	0.000	0.000	0.000	0.000	0.000	0.000
6. Combustion turbine(s)	0.000	0.000	0.000	0.000	0.000	0.000
7. Steam turbine(s)	0.000	0.000	0.000	0.000	0.000	0.000
8. Fuel Cell(s)	0.000	0.000	0.000	0.000	0.000	0.000
9. Hydroelectric	0.000	0.000	0.000	0.000	0.000	0.000
10, Photovoltaic	0.000	0.000	0.000	0.000	0.000	0.000
11. Storage	0.000	0.000	0.000	0.000	0.000	0.000
12. Wind turbine(s)	0.000	0.000	0.000	0.000	0.000	0.000
13. Other	0.000	0.000	0.000	0.000	0.000	0.000
14. Total	0.000	0.000	0.000	0.000	0.000	0.000

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	CA - San Bernardino				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part		State	BA ID	Error No.	Error Description/Override Comment	Type	Override
6	A	CA	2775	626	Please review Residential Reporting Year Costs (Line 5 + Line 6). Values should be reported in thousand dollars. The calculated costs/kWh should be below the industry average of 80 cents/kWh. Data corrected	W	
6	A	CA	2775	634	Please review Residential Life Cycle costs (Line 7 + Line 8). Values should be reported in thousand dollars. The calculated costs/kWh should be below the industry average of 4 cents/kWh. Data are now corrected	W	
6	C	CA	0	709	Dynamic Pricing programs were reported last year, but not this year. Dynamic pricing programs are now reported	W	