Chapter 17 Energy

17.1 Introduction

This chapter describes the environmental setting, methods of analysis, and potential Project impacts on energy resources. The energy resource analysis addresses the Project's energy requirements for construction and operation, the potential effects of the Project on local and regional energy supplies, compliance of the Project with energy standards, and conformance of the Project to energy conservation efforts.

The study area for electricity supply for construction and operations is the regional electricity transmission and distribution system, including Pacific Gas and Electric Company (PG&E) and the Western Area Power Administration (WAPA), as well as California's statewide electricity system more broadly. The four-county area in which Project facilities and equipment would operate is used as a proxy for the regional electricity transmission system study area. The boundaries of the potentially affected regional transmission system would ultimately be defined through a system impact study conducted by the electricity service provider, as required by standards and regulations prior to the construction and operation of the Project. The electricity supply study area is used to assess impacts on regional energy supply and peak and base period electricity demand resulting from including the Project in the regional electric transmission system.

As described in Chapter 2, *Project Description and Alternatives*, operation of the Project would occur in coordination with the CVP/SWP system, thus potentially affecting CVP/SWP operations, including energy consumption and energy generation. Therefore, the energy resource analysis also addresses the effects of the Project on CVP/SWP energy use and energy generation. The study area for potential impacts on the CVP/SWP electricity generation system consists of the geographic reach of CVP/SWP operations, including where CVP/SWP facilities generate and consume electricity. The electricity generation study area is applied for modeling of impacts on net electricity generation and electricity consumption of the CVP/SWP system as a result of adding the Project to the CVP/SWP system.

Construction and operation of the Project would utilize energy resources, including petroleum-based fuels (gasoline, diesel fuel), that would be supplied through the regional liquid fuel distribution infrastructure. The study area for potential impacts associated with petroleum-based fuel consumption consists of Tehama, Glenn, Colusa, and Yolo Counties, where the Authority expects most fuel purchases during Project construction and operations would occur.

Tables 17-1a and 17-1b summarize the CEQA determinations and NEPA conclusions for construction and operations impacts, respectively, between alternatives that are described in the impact analysis.

Table 17-1a. Summary of Construction Impacts and Mitigation Measures for Energy Resources

Alternative	Level of Significance Before Mitigation	Mitigation Measures	Level of Significance After Mitigation
Impact EN-1: Potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources during construction or operation			
No Project	NI/NE	-	NI/NE
Alternative 1	LTS/NE	-	LTS/NE
Alternative 2	LTS/NE	-	LTS/NE
Alternative 3	LTS/NE	-	LTS/NE
Impact EN-2: Conflict with or obstruct a state or local plan for renewable energy or energy efficiency			
No Project	NI/NE	-	NI/NE
Alternative 1	NI/NE	-	NI/NE
Alternative 2	NI/NE	-	NI/NE
Alternative 3	NI/NE	-	NI/NE
Impact EN-3: Place a substantial demand on regional energy supply or require substantial additional capacity or substantially increase peak and base period electricity demand			
No Project	NI/NE	-	NI/NE
Alternative 1	LTS/NE	-	LTS/NE
Alternative 2	LTS/NE	-	LTS/NE
Alternative 3	LTS/NE	-	LTS/NE

Notes:
NI = CEQA no impact
LTS = CEQA less-than-significant impact
NE = NEPA no effect or no adverse effect

Table 17-1b. Summary of Operations Impacts and Mitigation Measures for Energy Resources

Alternative	Level of Significance Before Mitigation	Mitigation Measures	Level of Significance After Mitigation
Impact EN-1: Potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources during construction or operation			
No Project	NI/NE	-	NI/NE
Alternative 1	LTS/NE	-	LTS/NE
Alternative 2	LTS/NE	-	LTS/NE
Alternative 3	LTS/NE	-	LTS/NE
Impact EN-2: Conflict with or obstruct a state or local plan for renewable energy or energy efficiency			
No Project	NI/NE	-	NI/NE
Alternative 1	NI/NE	-	NI/NE
Alternative 2	NI/NE	-	NI/NE
Alternative 3	NI/NE	-	NI/NE
Impact EN-3: Place a substantial demand on regional energy supply or require substantial additional capacity or substantially increase peak and base period electricity demand.			
No Project	NI/NE	-	NI/NE

Alternative	Level of Significance Before Mitigation	Mitigation Measures	Level of Significance After Mitigation
Alternative 1	LTS/NE	-	LTS/NE
Alternative 2	LTS/NE	-	LTS/NE
Alternative 3	LTS/NE	-	LTS/NE

Notes:
NI = CEQA no impact
LTS = CEQA less-than-significant impact
NE = NEPA no effect or no adverse effect

17.2 Environmental Setting

17.2.1. Electricity

17.2.1.1. Electricity Generation

California's electrical infrastructure is a complex grid of energy generation facilities connected by high-voltage electric transmission lines and lower-voltage distribution lines. Table 17-2a and Table 17-2b show the breakdown of utility-scale in-state generation plus net electricity imports for 2019 and 2018, respectively. Table 17-3 shows electricity generation in the state by fuel type.

Total system electricity generation for California was 278,184 gigawatt-hours (GWh) in 2019 and 285,488 in 2018, a decrease of 2.6% (7,304 GWh). Approximately two-thirds of total system electricity generation is from in-state sources. Approximately one-third of California's electricity supply is imported from the Pacific Northwest and the Southwest (California Energy Commission 2019:1, 2020a:1). From 2018 to 2019, total in-state solar generation increased by 4.89% (1,248 GWh), wind energy decreased by 2.83% (398 GWh), and large hydroelectric energy increased by 50% (11,049 GWh). Large hydroelectric generation increased from 22,096 GWh in 2018 to 33,145 GWh in 2019, and small hydroelectric generation increased from to 4,248 GWh in 2018 to 5,349 GWh in 2019. In California, 2018 was drought year and 2019 was not a drought year (National Oceanic and Atmospheric Administration 2021); this difference contributed to the increase in large and small facility hydroelectric generation from 2018 to 2019. The gain from hydroelectric generation in 2019 was offset by a 15% decrease in net imports to 77,229 GWh in 2019, down 13,418 GWh from 90,647 GWh in 2018.

Nuclear generation decreased by 11.52% (2,105 GWh) between 2018 and 2019; nuclear energy combined with large hydroelectric and renewable energy accounted for nearly 50% of California's in-state electricity generation in 2018 and 57% in 2019 (California Energy Commission 2019:1, 2020a:1).

Total electricity use in the state, including in-state generation and imports, declined slightly (2.73%) from 2018 to 2019. In recent years, significant amounts of new renewable generation have reached commercial operation, driven in part by California's Renewable Portfolio Standard (RPS) of 60% by 2030 and a requirement that all the state's electricity come from carbon-free resources by 2045 (California Independent System Operator 2020:32).

California divides hydroelectric power generation into two categories: large hydro, which is defined as facilities larger than 30 megawatts (MW) generation capacity, and small hydro, which includes all other hydroelectric facilities. Small hydroelectric plants qualify as renewable energy under the RPS; certain hydroelectric plants larger than 30 MW generation capacity also qualify under specific provisions of the RPS (California Energy Commission 2020b:1). In 2019, hydro-produced electricity used by California totaled approximately 38,494 GWh, or 19.21% of California's total system generation. A total of 271 hydroelectric facilities, with an installed capacity of 14,038 MW, operate in California. The amount of hydroelectricity produced varies each year and is largely dependent on snowmelt runoff and rainfall. The annual average hydroelectric generation from 1983 through 2019 is 34,476.3 GWh (California Energy Commission 2021:1).

Table 17-2a. 2019 Total System Electricity Generation

Fuel Type	California In-State Generation (GWh)	California In-State Generation (%)	Pacific Northwest Imports (GWh)	Southwest Imports (GWh)	Total Imports (GWh)	Total Imports (%)	California Power Mix[1] (GWh)	California Power Mix[1] (%)
2019 Total System Electricity Generation								
Nonrenewables								
Coal	248	0.12%	219	7,765	7,985	10.34%	8,233	2.96%
Natural Gas	86,136	42.97%	62	8,859	8,921	11.55%	95,507	34.23%
Oil	36	0.02%	0	0	0	0.00%	36	0.01%
Other[2]	411	0.20%	0	11	11	0.01%	422	0.15%
Nuclear	16,163	8.06%	39	8,743	8,782	11.37%	24,975	8.98%
Large Hydro[3]	33,145	16.53%	6,387	1,071	7,458	9.66%	40,603	14.62%
Unspecified Sources of Power[4]	0	0.00%	6,609	13,767	20,376	26.38%	20,376	7.34%
Nonrenewables and Unspecified Totals	136,139	67.91%	13,315	40,218	53,533	69.32%	190,152	68.30%
Renewables[5]								
Biomass	5,851	2.92%	903	33	936	1.21%	6,787	2.44%
Geothermal	10,943	5.46%	99	2,218	2,318	3.00%	13,260	4.77%
Small Hydro[6]	5,349	2.67%	292	4	296	0.38%	5,646	2.03%
Solar	28,513	14.22%	282	5,295	5,577	7.22%	34,090	12.28%
Wind	13,680	6.82%	9,038	5,531	14,569	18.87%	28,249	10.17%
Renewables Totals	64,336	32.09%	10,615	13,081	23,696	30.68%	88,032	31.70%
System Total	200,475	100.00%	23,930	53,299	77,229	100.00%	278,184	100.00%

Table 17-2b. 2018 Total System Electricity Generation

Fuel Type	California In-State Generation (GWh)	California In-State Generation (%)	Pacific Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix[1] (GWh)	California Power Mix (%)
2018 Total System Electricity Generation						
Nonrenewables						
Coal	294	0.15%	399	8,740	9,433	3.30%
Natural Gas	90,691	46.54%	49	8,904	99,644	34.91%
Oil	35	0.02%	0	0	35	0.01%
Other[2]	430	0.22%	0	9	439	0.15%
Nuclear	18,268	9.38%	0	7,573	25,841	9.05%
Large Hydro[3]	22,096	11.34%	7,418	985	30,499	10.68%
Unspecified Sources of Power[4]	–	–	17,576	12,519	30,095	10.54%
Nonrenewables and Unspecified Totals	131,814	67.65%	25,442	38,730	195,986	68.64%
Renewables[5]						
Biomass	5,909	3.03%	772	26	6,707	2.35%
Geothermal	11,528	5.92%	171	1,269	12,968	4.54%
Small Hydro[6]	4,248	2.18%	334	1	4,583	1.61%
Solar	27,265	13.99%	174	5,094	32,533	11.40%
Wind	14,078	7.23%	12,623	6,010	32,711	11.46%
Renewables Totals	63,028	32.35%	14,074	12,400	89,502	31.36%
System Total	194,842	100.00%	39,517	51,130	285,488	100.00%

Tables 17-2a and 17-2b Source: California Energy Commission 2019:1, 2020a:1

Tables 17-2a and 17-2b Notes:

1 Total of in-state and imported generation by fuel type.

2 Includes other nonrenewable fuels, such as petroleum coke and waste heat.

3 Defined as equal to or greater than 30 MW in generating capacity.

4 Unspecified power refers to electricity that is not traceable to a specific generating facility, such as electricity traded through open market transactions.

5 Includes wind and solar generation.

6 Defined as less than 30 MW in generating capacity.

GWh = gigawatt-hours; MW = megawatt

Table 17-3. In-State Electricity Generation by Fuel Type (GWh)

Primary Fuel	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	2,810	3,010	3,032	2,889	3,012	2,920	2,968	2,835	2,562	2,286	2,096	1,262	824	802	309	324	302	294	248
Petroleum Coke	1,231	1,265	1,237	1,197	1,271	1,270	1,249	1,142	1,173	1,120	1,024	318	194	208	229	207	246	207	191
Biomass	5,782	6,217	6,094	6,082	6,080	5,865	5,766	5,915	6,122	5,993	6,066	6,211	6,559	6,785	6,367	5,905	5,847	5,913	5,851
Geothermal	13,525	13,396	13,329	13,494	13,292	13,093	13,084	12,907	12,907	12,740	12,685	12,733	12,510	12,186	11,994	11,582	11,745	11,528	10,943
Nuclear	33,294	34,353	35,594	30,241	36,155	32,036	35,698	32,482	31,509	32,214	36,666	18,491	17,860	17,027	18,525	18,931	17,925	18,268	16,163
Natural Gas	116,151	92,490	94,194	105,040	96,893	108,952	120,247	122,799	117,099	109,682	91,063	121,777	120,863	121,855	117,565	98,880	89,588	90,711	86,136
Large Hydro	20,144	26,003	30,325	28,945	33,334	40,952	22,640	19,887	23,659	28,483	35,682	22,737	20,319	13,739	11,569	24,410	36,920	22,043	33,145
Small Hydro	4,844	5,356	5,996	5,545	6,928	7,607	4,466	4,573	4,880	5,707	7,055	4,724	3,782	2,742	2,427	4,576	6,383	4,250	5,349
Solar PV	3	2	2	2	2	2	2	3	17	90	226	1,025	3,796	9,148	13,057	17,385	21,895	25,005	26,210
Solar Thermal	834	848	757	739	658	614	666	730	841	879	889	867	686	1,624	2,446	2,548	2,464	2,545	2,303
Wind	3,242	3,546	3,316	4,258	4,084	4,902	5,570	5,724	6,249	6,172	7,598	9,242	11,964	13,104	12,191	13,499	12,867	14,024	13,680
Waste Heat	242	240	294	237	221	259	233	278	233	241	267	217	222	237	177	182	163	223	220
Oil	379	87	103	127	148	134	103	92	67	52	36	48	38	45	54	37	33	35	36
Grand Total	202,480	186,815	194,270	198,796	202,079	218,604	212,693	209,367	207,317	205,657	201,353	199,652	199,618	199,503	196,910	198,466	206,378	195,044	200,475

Source: California Energy Commission 2020c
GWh = gigawatt-hours.

This page intentionally left blank

17.2.1.2. Electricity Demand

The California Energy Commission (CEC) estimates total and peak demands over time using middle-, high-, and low-range demand assumptions. A mid-range projection suggests that total demand will grow at an annual rate of 1.2% from 2019 through 2030 and that peak demand will grow at an annual rate of 0.2% to 0.6%. The CEC is in the process of updating its projections and expects that projections through 2035 will become available in the winter of 2021. Recent and projected growth trends are shown in Table 17-4 (California Energy Commission 2020c:1).

Table 17-4. CEDU 2020 Mid-, High-, and Low-Case Demand Baseline—Statewide Consumption (GWh) and Net Peak Demand (MW)

Year	*CEDU 2020* Mid-Energy Demand	*CEDU 2020* High-Energy Demand	*CEDU 2020* Low-Energy Demand
1990	227,599	227,599	227,599
2000	261,414	261,414	261,414
2010	272,693	272,693	272,693
2019	277,755	277,755	277,755
2020	273,516	276,563	270,688
2021	277,410	282,502	272,645
2023	290,951	298,880	283,031
2025	300,233	310,477	289,295
2030	317,217	333,784	299,054
1990–2000	1.4%	1.4%	1.4%
2000–2010	0.4%	0.4%	0.4%
2010–2019	0.2%	0.2%	0.2%
2019-2021	-0.1%	0.9%	-0.9%
2019–2023	1.2%	1.8%	0.5%
2019-2025	1.3%	1.9%	0.7%
2019–2030	1.2%	1.7%	0.7%
Year	***CEDU 2020* Mid-Energy Demand**	***CEDU 2020* High-Energy Demand**	***CEDU 2020* Low-Energy Demand**
1990	47,120	47,120	47,120
2000	53,528	53,528	53,528
2010	62,069	62,069	62,069
2019	60,606	60,606	60,606
2020[a]	60,762	60,762	60,762
2021	60,879	61,614	60,203
2023	61,727	63,902	59,761
2025	62,583	65,574	59,968
2030	64,738	69,434	60,840
1990–2000	1.3%	1.3%	1.3%
2000–2010	1.5%	1.5%	1.5%
2010–2019	-0.3%	-0.3%	-0.3%
2020–2021	0.2%	1.4%	-0.9%
2020–2023	0.5%	1.7%	-0.6%
2020–2025	0.6%	1.5%	-0.3%
2025–2030	0.6%	1.3%	0.0%

Source: Garcia pers. comm.:1
Notes: The average annual growth rates can be compared, and the net peak MW are comparable to one another.
[a] Weather normalized: CEDU 2020 forecast is weather normalized using actual 2020 peak demand data.
CED = California energy demand forecast; CEDU = California energy demand forecast update; GWh = gigawatt-hours; MW = megawatt

17.2.1.3. Electricity Consumption

Annual electricity consumption for the four counties in the electricity supply study area in 2019 is shown in Table 17-5 (California Energy Commission 2020d:1). Total electricity consumption for the four-county electricity supply study area in 2019 was approximately 3,174 GWh, including 1,963.04 GWh (61.8%) of nonresidential consumption and 1,210.98 GWh (38.2%) of residential consumption.

Approximately 54% of the total electricity consumption for 2019 in the four-county electricity supply study area was in Yolo County; Tehama County represented approximately 24% of the total consumption in 2019. Annual electricity consumption for Northern California in 2019 was 115,240 GWh (California Energy Commission 2020e:1-2).

Table 17-5. Annual Electricity Consumption by County for the Electricity Supply Study Area in 2019 (GWh)

County	Nonresidential	Residential	Total	Percent
Colusa	217.85	67.63	285.49	9.0%
Glenn	297.27	96.83	394.10	12.4%
Tehama	265.95	507.74	773.69	24.4%
Yolo	1,181.97	538.78	1,720.75	54.2%
Total	1,963.04	1,210.98	3,174.03	100.0%

Source: California Energy Commission 2020d:1
GWh = gigawatt-hours

17.2.2. Petroleum Products

Tables 17-6 and 17-7 show 2018 and 2019 annual gasoline and diesel fuel sales for the four counties where most fuel purchases associated with the Project are likely to occur. Gasoline and diesel fuel sales data are reported annually by the CEC Supply Analysis Office (California Energy Commission 2020f:1-2). Survey data are collected for retail gasoline sales and retail diesel fuel sales. Survey data are not available for nonretail sales. The CEC Supply Analysis Office estimates that nonretail sales of diesel fuel are approximately 52.8% of total sales and retail sales of diesel fuel are approximately 47.2% of total sales (California Energy Commission 2020f).

Table 17-6. Annual Gasoline Sales for the Petroleum Products Study Area (millions of gallons per year)

County	2018	2019
Colusa	13	13
Glenn	17	18
Tehama	31	30
Yolo	110	114

County	2018	2019
Total	171	175

Source: California Energy Commission 2020f:1-2

Table 17-7. Annual Diesel Fuel Sales for the Petroleum Products Study Area (millions of gallons per year)

County	2018			2019		
	Retail Sales	Nonretail	Total	Retail Sales	Nonretail	Total
Colusa	4	4.5	8.5	7	7.8	14.8
Glenn	17	19.0	36.0	19	21.3	40.3
Tehama	20	22.4	42.4	18	20.1	38.1
Yolo	28	31.3	59.3	26	29.1	55.1
Total	69.0	77.2	146.2	70.0	78.3	148.3

Source: California Energy Commission 2020f:1-2

17.3 Methods of Analysis

Energy production and energy consumption are evaluated in the context of energy that is used and energy that is generated during construction and operations. Energy sources evaluated are electricity and petroleum products, and the methods for each are described below.

17.3.1. Construction

The analysis addresses potential impacts related to the Project's construction energy demands, including electric power and petroleum-based fuels consumed during Project construction. Project energy consumption during operations includes fuel consumed for operation of vehicles during construction and fuel and electricity consumed for equipment and facilities. The analysis also considers application of energy resource BMPs for Project construction. These BMPs are described in Appendix 2D, *Best Management Practices, Management Plans, and Technical Studies*. In accordance with BMP-1, Conformance with Applicable Design Standards and Building Codes, the Authority will ensure conformance with applicable design standards and building codes for equipment, including electrical generation equipment, substations, and transmission lines, buildings, and utility and infrastructure verification and/or relocation. Electricity-consuming equipment and facilities for the Project will meet current standards and codes, including energy efficiency standards, because they would be required to conform with applicable design standards and building codes. In accordance with BMP-27, Development and Implementation of a Construction Equipment Exhaust Reduction Plan, the Authority will implement measures to reduce construction criteria pollutant emissions, and that would result in associated reduced construction energy consumption. According to BMP-27, engines meeting Tier 4 air emissions standards will be used in most off-road construction equipment during Project construction. Equipment manufacturers have reported that Tier 4 engines are more fuel efficient than engines meeting previous Tier standards (Holt 2010; Power Engineering 2011); however, the Tier 4 engine standard is an air emissions standard, not a fuel efficiency standard, and fuel efficiency gains from application of Tier 4 engines will vary by engine type, engine manufacturer, and other factors. Air emissions modeling from which construction equipment and construction vehicle fuel consumption is derived is also based on the assumption that on-road vehicles used during the construction period will have engines certified to the 2010 model year or newer model year heavy-duty diesel engine air emissions standards.

17.3.1.1. Electricity

The analysis of construction impacts on energy resources examines annual construction-related electricity demands for each alternative, including electricity consumption for operation of construction equipment and temporary construction buildings. Construction electricity demand for each alternative is evaluated against the peak and base period demands for electricity in the four-county electricity supply study area, as well as with respect to compliance with existing energy efficiency standards.

17.3.1.2. Petroleum Products

Total diesel fuel consumption and total gasoline consumption over the 6-year construction period is estimated based on air quality and greenhouse gas (GHG) modeling results. Air quality and GHG modeling is described in detail in Chapter 20, *Air Quality*, and Chapter 21, *Greenhouse Gas Emissions*. The models applied for estimating construction GHG emissions do not directly estimate construction vehicle and equipment fuel consumption. Therefore, conversion factors are applied for the energy analysis to convert modeled GHG emissions from construction vehicles and equipment to gasoline and diesel fuel consumption.

In addition to estimating total diesel and gasoline consumption for Project construction over the construction period, the analysis compares annual gasoline and diesel fuel consumption for Project construction to the annual amounts of diesel fuel and gasoline consumed (based on sales data) in the four-county petroleum products study area. Based on fuel consumption derived from air quality and GHG modeling, the peak year for petroleum products consumption during the construction period would be 2026. Accordingly, this peak consumption year was selected to compare the annual fuel demand for Project construction to the annual petroleum products consumption in the petroleum products study area.

Construction energy consumption impacts include fuel consumption for construction of all Project facilities, fuel consumption for the use of haul trucks to transport construction materials and construction debris, based on vehicle miles traveled (VMT). A description of vehicles and construction equipment used for construction is in Appendix 2C, *Construction Means, Methods, and Assumptions*. Fuel would be consumed for transport of construction workers to/from construction sites. Construction workers may come from areas outside of the four-county petroleum products study area, including the Sacramento area.

17.3.2. Operations

The analysis addresses potential impacts related to the Project's operational energy demands, including electric power and petroleum-based fuels consumed during Project operations. Project energy consumption during operations includes fuel consumed for operation of vehicles accessing recreational areas of the Project and fuel and electricity consumed for operation and maintenance of Project equipment and facilities. The analysis also considers application of energy resource BMPs for Project operations. BMP-1 would serve to reduce operations energy consumption, including conformance with applicable operation and maintenance standards and codes for equipment, including electrical generation equipment, substations, and transmission lines, including but not limited to California Energy Efficiency Standards for Residential and Nonresidential Buildings. BMP-1 is related to consumption of electric power and petroleum products to the extent that conformance to design standards and building codes results in specification of more energy-efficient buildings and equipment and operating and maintenance standards that maintain the efficient operation of the buildings and equipment. Design standards and building codes include both energy efficiency standards and other standards (e.g., building materials), and, therefore, their combined effect on system-wide energy consumption cannot be directly estimated.

17.3.2.1. Electricity

This chapter provides an analysis of Alternative 1A and Alternative 1B, which are both considered under Alternative 1 for the purposes of operational impact analysis based on information relying on hydrologic modeling output (i.e., electricity). The model results represent two different operations options under Alternative 1 as a result of different participation for Reclamation.

Hydropower generation would be influenced by the timing of releases, movement of water, and seasonal operational decisions. The energy consumption and generation of the Project during operations would involve multiple facilities (e.g., Funks PGP, TRR East or TRR West PGP) and interconnections to the existing electric power grid; electric power generated by the Project would be supplied to the regional electric transmission grid, and electric power used by the Project would be supplied from the regional electric transmission grid. The Project electric power generation facilities would individually have nameplate capacities less than 40 MW; the two Project electric power generation facilities would not be collocated and would be separately operated. The Project would not self-supply electricity from Project electric power generation equipment to Project electric power-consuming equipment.

Electric power generation capacity and electricity consumption modeling for the CVP/SWP system, including the Project, was conducted using the LTGEN and SWP_Power models. These are two commonly used, publicly available models developed by Reclamation and California Department of Water Resources (DWR). These models use reservoir storage and release data from the CALSIM II model to estimate monthly energy consumption. Energy generation is calculated using energy factors based on water discharges provided by WAPA for CVP facilities and by DWR for SWP facilities. Electric power generation capacity fluctuates with varying reservoir levels and scheduled water releases throughout the CVP/SWP system. Monthly data for the CVP/SWP system show that generally electric power production for the CVP/SWP system is higher during summer months when reservoir levels are higher and when water is released to satisfy water delivery requirements of CVP/SWP customers. The Project would be operated in coordination with the CVP/SWP. Operation of the Project would pump water south of the Delta and include exchanges between the Project and CVP/SWP. As such, the Authority expects that long-term average electricity consumption of the CVP/SWP system would change under Project conditions. The modeling analysis models effects of the Project on CVP/SWP system-wide electricity generation and electricity consumption. For the purposes of planning and CEQA/NEPA analysis and based on the current level of design and knowledge of the Project, the LTGEN and SWP_Power modeling provides an appropriate understanding of the level of impacts. The electricity modeling conducted for the Project considers the potential effects of the Project on electricity consumption and electricity generation for the entire CVP/SWP system, including the addition of the Project.

Energy resource impacts are evaluated for each alternative, including a collective assessment of energy resource impacts on operations for all CVP/SWP system energy-consuming facilities and all CVP/SWP system energy-producing facilities in the electricity generation study area. The net electricity generation for operation of Alternatives 1A, 1B, 2, and 3 (including the Project and the CVP/SWP system) is compared to the No Action Alternative net electricity generation for CVP and SWP facility operation, including electricity generation and electricity consumption for pumping and delivery of water. Average combined CVP and SWP electricity use for pumping and delivery of water from the Delta, including storage in San Luis Reservoir, pumping over the Tehachapi Mountains, and recovery of electricity at generating stations along the California Aqueduct, is approximately 7,000 GWh per year.

17.3.2.2. Petroleum Products

The petroleum products analysis estimates diesel fuel and gasoline consumption for Project operations and maintenance for the modeled Project operating period of 2030–2040, including gasoline and diesel fuel consumption for Project operations and maintenance vehicles and equipment and fuel consumption for passenger vehicles of users of Sites Reservoir recreational facilities, based on VMT. The gasoline and diesel fuel consumption for operation of the Project, including gasoline and diesel fuel consumption of recreational users, is compared to the supply of gasoline and diesel fuel (based on sales data) in the four-county petroleum products study area.

17.3.3. Thresholds of Significance

An impact on energy resources would be considered significant if the Project would:

- Result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources during construction or operation.
- Conflict with or obstruct a state or local plan for renewable energy or energy efficiency.
- Place a substantial demand on regional energy supply or require substantial additional capacity or substantially increase peak and base period electricity demand.

17.4 Modeling Results

The following section presents the modeling results for electrical consumption and generation and petroleum product consumption during construction and operation of the alternatives. These results are incorporated as appropriate and as described in Section 17.3, *Methods of Analysis*, into the impact analysis. As noted above in Section 17.3, modeling results for Alternatives 1A and 1B are presented for electricity under operating conditions because these are two options involving Reclamation under Alternative 1 that result in slightly different operations and influence the use and generation of power; for all other modeling there is no difference between Alternative 1A and 1B and thus only results for Alternative 1 are presented. In other words, Alternative 1A and 1B are identical for petroleum product consumption during construction and operations and are identical for electrical consumption during construction.

17.4.1. Electricity

Modeling electricity consumption for construction is based on temporary electrical requirements for various construction equipment during the construction period. Modeling electricity consumption is modeled separately for Project construction and Project operation. Modeling electricity consumption for construction is based on temporary electrical requirements for various construction equipment during the construction period. Modeling of operations include modeling of electricity consumption for Project operations, modeling electricity generation for Project operation, and modeling electricity consumption and electricity generation of the CVP/SWP system without inclusion of the Project (the No Action Alternative) and with inclusion of the Project (Alternatives 1, 2, and 3).

17.4.1.1. Construction

Temporary electricity requirements for construction of Alternatives 1, 2, and 3 for the three-phase electric power system were estimated in units of kilovolt-amperes (kVA). Temporary Project facilities with electric power load include the contractor's and owner's office complexes, as well as contractors' shop complexes. Also included in Project construction electricity requirements are temporary construction material production sites with electric power load, which include onsite quarries, concrete batch plants, asphalt batch plants, and transition zones. A list of Project construction facilities and equipment is shown in Table 17-8 and would support the construction of dams, saddle dams, I/O Works, roads, and conveyance structures.

Electricity requirements for Project construction that were estimated in units of kVA were then converted to electricity consumption in units of kilowatts (kW) (see Table 17-8) to facilitate a comparison to the electricity consumption for the four-county electricity supply study area.[1] Temporary electricity requirements for construction of Alternatives 1 and 3 would be 10,300 kVA, equivalent to electricity consumption of 17,839.4 kW or 17.8 MW. Construction electricity consumption would generally be the same for Alternatives 1, 2, and 3, with the exception of the Cement Deep Soil Mixing Batch Plant, which would only be applicable to Alternatives 1 and 3, and construction of TRR East. Temporary electricity requirements for construction of Alternative 2 would be 9,100 kVA, equivalent to electricity consumption of 15,761 kW or 15.7 MW.

[1] Conversion of three-phase electricity consumption in units of kVA to electricity consumption in units of kV uses the following formula: $\sqrt{3}$*kVA = kW.

Table 17-8. Temporary Electricity Requirements and Consumption for Construction of Alternatives 1, 2, and 3 (kVA, kW, and kWh per year)

Location/Facility	Required Load, Three-Phase, kVA	Normalized kVA[1]	kW	Annual Use (hours/year)	Annual electricity (kWh/year)
Golden Gate and Sites Dams					
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100	1,091,160
Golden Gate Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1,500	2,598,000
Sites Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1,500	2,598,000
Golden Gate Concrete Batch Plant	600	1,039.2	1,039.2	1,500	1,558,800
Sites Concrete Batch Plant	600	1,039.2	1,039.2	1,500	1,558,800
Contractor's Shop Complex	300	519.6	519.6	1,500	779,400
Saddle Dams					
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100	1,091,160
Saddle Dams Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1500	2,598,000
Concrete Batch Plant	600	1,039.2	1,039.2	1,500	1,558,800
Contractor's Shop Complex	300	519.6	519.6	1,500	779,400
I/O Facilities					
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100	1,091,160
Concrete Batch Plant	600	1,039.2	1,039.2	1,500	1,558,800
Contractor's Shop Complex	200	346.4	346.4	1,500	519,600
Roads					
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100	1,091,160
Asphalt Batch Plant	600	1,039.2	1,039.2	1,500	1,558,800
Contractor's Shop Complex	200	346.4	346.4	1,500	519,600
Conveyance					
Contractor's and Owner's Office Complex (3)	900	1,558.8	1,558.8	2,100	3,273,480
Concrete Batch Plant & CDSM Batch Plant (2)	1,200	2,078.5	2,078.5	1,500	3,117,750
Total Alternatives 1 and 3 [2]	**10,300**	**17,839.4**	**17,839.4**	**-**	**28,941,870**
Total Alternative 2	**9,100**	**15,761**	**15,761**	**-**	**25,824,120**

Source: Chapter 2, *Project Description and Alternatives*, Table 2-9

[1] Conversion of three-phase electricity consumption in units of kVA to electricity consumption in units of kV uses the following formula: √3*kVA = kW.

[2] Note: Construction electricity requirements and electricity consumption are the same for Alternatives 1 and 3.

[3] CDSM = Cement Deep Soil Mixing; CDSM is only applicable to Alternatives 1 and 3

kVA = kilovolt-ampere; kW = kilowatt

17.4.1.2. Operation

Annual electricity generation and annual electricity consumption for Project operation and CVP/SWP system operation are shown in Table 17-9 (Alternatives 1A and 1B), Table 17-10 (Alternative 2), and Table 17-11 (Alternative 3) in units of GWh/year. Table 17-9, Table 17-10, and Table 17-11 also show the annual electricity consumption in units of GWh/year for the No Action Alternative. The No Action Alternative includes existing facilities that would continue to operate in the absence of the proposed Sites Reservoir Project; these existing facilities include the RBPP and TC Canal, GCID Hamilton City Pumping Station and GCID Main Canal, and Funks Reservoir. Operation of these existing facilities consumes electricity; the electricity consumption of these existing facilities is included in the No Action Alternative in Table 17-9, Table 17-10, and Table 17-11 under the *Alternative 1 Pumping Facilities*, *Alternative 2 Pumping Facilities*, and *Alternative 3 Pumping Facilities* headings, respectively. The No Action Alternative is therefore a net consumer of electricity.

Modeling of CVP/SWP system operations includes CVP and SWP electric power facilities (electricity generation) and CVP and SWP pumping facilities (electricity consumption) and modeling of net energy generation (electricity generation minus electricity consumption) for the CVP/SWP system. Total modeled CVP/SWP facility generating capacities (in units of MW) for Alternatives 1A and 1B, 2, and 3 are also identified in the aforementioned tables. Electricity generation and consumption were estimated using different models with simulated results from the CALSIM II model (Appendix 17A, *CVP/SWP Power Modeling*, for a description of electric power modeling methods and results). Estimates of net electricity generation are provided for long-term average conditions and for Dry and Critically Dry Water Years.

Table 17-9 (Alternative 1A, 1B), Table 17-10 (Alternative 2), and Table 17-11 (Alternative 3) show the net electricity generation (electricity generation minus electricity consumption) for *All Facilities* (CVP, SWP, and Alternative) in units of GWh/year for long-term average and for Dry and Critically Dry Water Years. The tables also show the percent change in net electricity generation (GWh) for each Alternative as compared to net electricity generation of the No Action Alternative for long-term average and Dry and Critically Dry Water Years. Net electricity generation of all facilities decreases for all Alternatives as compared to the net electricity generation of the No Action Alternative for both long-term average and Dry and Critically Dry Water Years.

Table 17-9. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1]—No Action Alternative (NAA), Alternative 1A and Alternative 1B

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 1A	Alternative 1B	Difference between Alternative 1B and NAA[2]	Difference between Alternative 1A and NAA[2]
CVP Power Facilities							
Capacity	*Total of all Facilities at load center (MW)*	Long-Term[3]	1,683	1,686	1,687	4	2
		Dry and Critically Dry Water Years[4]	1,588	1,592	1,594	6	4
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	4,685	4,689	4,689	5	4
		Dry and Critically Dry Water Years	3,406	3,415	3,411	5	4
CVP Pumping Facilities							
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	1,305	1,309	1,312	7	4
		Dry and Critically Dry Water Years	1,066	1,070	1,078	12	4
Off-peak pumping targets	*Percent of time off-peak target not met (%)*	Long-Term	0%	0%	0%	0%	0%
		Dry and Critically Dry Water Years	0%	0%	0%	0%	0%
Total CVP Facilities							
Net Generation[5]	*Total of all Facilities (GWh)*	Long-Term	3,380	3,380	3,377	-3	0
		Dry and Critically Dry Water Years	2,340	2,345	2,334	-7	4
SWP Power Facilities							
Capacity	*Total of all Facilities at load center (GWh)*	Long-Term	979	995	995	16	16
		Dry and Critically Dry Water Years	629	655	658	29	26
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	3,940	4,043	4,037	97	103
		Dry and Critically Dry Water Years	2,569	2,763	2,758	188	194

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 1A	Alternative 1B	Difference between Alternative 1B and NAA[2]	Difference between Alternative 1A and NAA[2]
SWP Pumping Facilities							
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	6,931	7,259	7,236	305	328
		Dry and Critically Dry Water Years	4,927	5,591	5,566	640	664
Off-peak pumping targets	*Percent of time off-peak target not met (%)*	Long-Term	27%	27%	27%	0%	0%
		Dry and Critically Dry Water Years	0%	0%	0%	0%	0%
Total SWP Facilities							
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-2,990	-3,216	-3,199	-208	-226
		Dry and Critically Dry Water Years	-2,357	-2,827	-2,809	-452	-470
Alternative 1 Power Facilities							
Capacity	*At load center (MW)*	Long-Term	0	5	5	5	5
		Dry and Critically Dry Water Years	0	8	8	8	8
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	42	45	45	42
		Dry and Critically Dry Water Years	0	67	67	67	67
Alternative 1 Pumping Facilities							
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	94	97	85	82
		Dry and Critically Dry Water Years	11	41	40	29	30
Total Alternative 1 Facilities							
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-12	-52	-52	-40	-39
		Dry and Critically Dry Water Years	-11	25	28	39	36

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 1A	Alternative 1B	Difference between Alternative 1B and NAA[2]	Difference between Alternative 1A and NAA[2]
All Facilities (CVP, SWP, and Alternative 1)[5, 6]							
Net Generation	*Total of all Facilities (GWh)*	Long-Term	377	112	126	-251	-265
		Dry and Critically Dry Water Years	-28	-457	-448	-420	-429
Net Generation	*Percent Change*	Long-Term	–	–	–	-66.6%	-70.4%
		Dry and Critically Dry Water Years	–	–	–	-1,500.9%	-1,535.0%
Energy Use [7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	–	4.8%	5.0%
		(GWh/GWh) Dry and Critically Dry Water Years	–	–	–	11.3%	11.6%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,248	8,663	8,645	397	415
		Dry and Critically Dry Water Years	6,004	6,702	6,684	680	698

Notes:

[1] Results are estimated using LTGEN and SWP_Power and Project_Power, using data from the CALSIM II model.

[2] Because of rounding of the energy values to whole numbers, some differences may appear to be off by ±1.

[3] Long-Term is the average quantity for the calendar years 1922–2003.

[4] Dry and Critically Dry Water Years is the average quantity for Dry and Critically Dry Water Years according to the Sacramento River 40-30-30 index.

[5] Net Generation for all facilities is the sum of Net Generation for CVP and SWP facilities and Net Generation for the Project.

[6] Project Facilities include Funks PGP and TRR East PGP.

[7] Combined CVP and SWP energy use for pumping and delivery of water.

CVP = Central Valley Project; GWh = gigawatt-hours; MW = megawatt; NAA = No Action Alternative; SWP = State Water Project.

The NAA is the current operation of the CVP and SWP facilities without the proposed Sites Reservoir Project. including existing CVP/SWP facilities electricity consumption and electricity generation. The NAA also includes electricity consumption of existing facilities (including RBPP and TC Canal, GCID Hamilton City Pumping Station and GCID Main Canal, and Funks Reservoir) that would continue to operate in the absence of the Project. These existing facilities consume electricity during operations but do not generate electricity during operations, therefore the net electricity generation for these facilities (electricity generation minus electricity consumption) for the No Action Alternative is negative for both long-term average and Dry and Critically Dry Water Years. Units for this table are noted in Column 1 for all rows. Different rows in this table have different units (e.g., the first-row units are MW, the second and third row units are GWh, fourth row units are in percent, etc.); therefore, units are not included in the table headers.

Table 17-10. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1] —No Action Alternative (NAA) and Alternative 2

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 2	Difference between Alternative 2 and NAA[2]
CVP Power Facilities					
Capacity	*Total of All Facilities at Load Center (MW)*	Long-Term[3]	1,683	1,685	2
		Dry and Critically Dry Water Years[4]	1,588	1,592	4
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	4,685	4,689	4
		Dry and Critically Dry Water Years	3,406	3,415	9
CVP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	1,305	1,309	4
		Dry and Critically Dry Water Years	1,066	1,070	4
Off-Peak Pumping Targets	*Percent of Time Off-Peak Target Not Met (%)*	Long-Term	0%	0%	0%
		Dry and Critically Dry Water Years	0%	0%	0%
Total CVP Facilities					
Net Generation[5]	*Total of All Facilities (GWh)*	Long-Term	3,380	3,379	0
		Dry and Critically Dry Water Years	2,340	2,345	5
SWP Power Facilities					
Capacity	*Total of All Facilities at Load Center (GWh)*	Long-Term	979	994	15
		Dry and Critically Dry Water Years	629	650	21
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	3,940	4,037	97
		Dry and Critically Dry Water Years	2,569	2,753	184
SWP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	6,931	7,239	309
		Dry and Critically Dry Water Years	4,927	5,558	631
Off-Peak Pumping Targets	*Percent of Time Off-Peak Target Not Met (%)*	Long-Term	27%	27%	0%
		Dry and Critically Dry Water Years	0%	0%	0%
Total SWP Facilities					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	-2,990	-3,202	-212
		Dry and Critically Dry Water Years	-2,357	-2,805	-448

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 2	Difference between Alternative 2 and NAA[2]
Alternative 2 Power Facilities					
Capacity	*At load center (MW)*	Long-Term	0	4	4
		Dry and Critically Dry Water Years	0	7	7
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	39	39
		Dry and Critically Dry Water Years	0	59	59
Alternative 2 Pumping Facilities					
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	88	76
		Dry and Critically Dry Water Years	11	40	29
Total Alternative 2 Facilities					
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-12	-49	-37
		Dry and Critically Dry Water Years	-11	20	30
All Facilities (CVP, SWP, and Alternative 2)[5, 6]					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	377	128	-249
		Dry and Critically Dry Water Years	-28	-440	-412
Net Generation	*Percent Change (GWh/GWh)*	Long-Term	–	–	-66.0%
		Dry and Critically Dry Water Years	–	–	-1,474%
Energy Use [7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	4.7%
		Dry and Critically Dry Water Years	–	–	11.1%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,248	8,637	389
		Dry and Critically Dry Water Years	6,004	6,667	663

Notes:
[1] Results are estimated using LTGEN and SWP_Power and Project_Power, using data from the CALSIM II model.
[2] Because of rounding of the energy values to whole numbers, some differences may appear to be off by ±1.
[3] Long-Term is the average quantity for the calendar years 1922–2003.
[4] Dry and Critically Dry Water Years is the average quantity for Dry and Critically Dry Water Years according to the Sacramento River 40-30-30 index.
[5] Net Generation for all facilities is the sum of Net Generation for CVP and SWP facilities and Net Generation for the Project.
[6] Project Facilities include Funks PGP and TRR West PGP.
[7] Combined CVP and SWP energy use for pumping and delivery of water from the Delta.
CVP = Central Valley Project; GWh = gigawatt-hours; MW = megawatt; NAA = No Action Alternative; SWP = State Water Project.
The NAA is the current operation of the CVP and SWP facilities without the proposed Sites Reservoir Project. including existing CVP/SWP facilities electricity consumption and electricity generation. The NAA also includes electricity

consumption of existing facilities (including RBPP and TC Canal, GCID Hamilton City Pumping Station and GCID Main Canal, and Funks Reservoir) that would continue to operate in the absence of the Project. These existing facilities consume electricity during operations but do not generate electricity during operations, therefore the net electricity generation for these facilities (electricity generation minus electricity consumption) for the No Action Alternative is negative for both long-term average and Dry and Critically Dry Water Years.
Units for this table are noted in Column 1 for all rows. Different rows in this table have different units (e.g., the first-row units are MW, the second and third row units are GWh, fourth row units are in percent, etc.); therefore, units are not included in the table headers.

Table 17-11. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1]—No Action Alternative (NAA) and Alternative 3

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 3	Difference between Alternative 3 and NAA[2]
CVP Power Facilities					
Capacity	*Total of All Facilities at Load Center (MW)*	Long-Term[3]	1,683	1,691	7
		Dry and Critically Dry Water Years[4]	1,588	1,602	13
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	4,685	4,692	7
		Dry and Critically Dry Water Years	3,406	3,423	17
CVP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	1,305	1,319	14
		Dry and Critically Dry Water Years	1,066	1,100	34
Off-Peak Pumping Targets	*Percent of Time Off-Peak Target Not Met (%)*	Long-Term	0%	0%	0%
		Dry and Critically Dry Water Years	0%	0%	0%
Total CVP Facilities					
Net Generation[5]	*Total of All Facilities (GWh)*	Long-Term	3,380	3,373	-7
		Dry and Critically Dry Water Years	2,340	2,323	-17
SWP Power Facilities					
Capacity	*Total of All Facilities at Load Center (GWh)*	Long-Term	979	994	15
		Dry and Critically Dry Water Years	629	655	26
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	3,940	4,020	80
		Dry and Critically Dry Water Years	2,569	2,730	161
SWP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	6,931	7,174	243
		Dry and Critically Dry Water Years	4,927	5,467	540

Parameter		Long-Term Average or Dry and Critically Dry Water Years Yearly Average	NAA	Alternative 3	Difference between Alternative 3 and NAA[2]
Off-Peak Pumping Targets	*Percent of Time Off-Peak Target Not Met (%)*	Long-Term	27%	27%	0%
		Dry and Critically Dry Water Years	0%	0%	0%
Total SWP Facilities					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	-2,990	-3,153	-163
		Dry and Critically Dry Water Years	-2,357	-2,737	-380
Alternative 3 Power Facilities					
Capacity	*At load center (MW)*	Long-Term	0	6	6
		Dry and Critically Dry Water Years	0	7	7
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	51	51
		Dry and Critically Dry Water Years	0	64	64
Alternative 3 Pumping Facilities					
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	104	92
		Dry and Critically Dry Water Years	11	40	29
Total Alternative 3 Facilities					
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-12	-53	-41
		Dry and Critically Dry Water Years	-11	25	35
All Facilities (CVP, SWP, and Alternative 3)[5, 6]					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	377	166	-211
		Dry and Critically Dry Water Years	-28	-389	-362
Net Generation	*Percent Change (GWh/GWh)*	Long-Term	–	–	-55.9%
		Dry and Critically Dry Water Years	–	–	-1,293%
Energy Use [7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	4.2%
		Dry and Critically Dry Water Years	–	–	10.1%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,248	8,597	349
		Dry and Critically Dry Water Years	6,004	6,607	604

Notes:

1 Results are estimated using LTGEN and SWP_Power and Project_Power, using data from the CALSIM II model.

2 Because of rounding of the energy values to whole numbers, some differences may appear to be off by ±1.

3 Long-Term is the average quantity for the calendar years 1922–2003.

4 Dry and Critically Dry Water Years is the average quantity for Dry and Critically Water Years according to the

Sacramento River 40-30-30 index.
[5] Net Generation for all facilities is the sum of Net Generation for CVP and SWP facilities and Net Generation for the Project.
[6] Project Facilities include Funks PGP and TRR East PGP.
[7] Combined CVP and SWP energy use for pumping and delivery of water from the Delta.
CVP = Central Valley Project; GWh = gigawatt-hours; MW = megawatt; NAA = No Action Alternative; SWP = State Water Project
The NAA is the current operation of the CVP and SWP facilities without the proposed Sites Reservoir Project. including existing CVP/SWP facilities electricity consumption and electricity generation. The NAA also includes electricity consumption of existing facilities (including RBPP and TC Canal, GCID Hamilton City Pumping Station and GCID Main Canal, and Funks Reservoir) that would continue to operate in the absence of the Project. These existing facilities consume electricity during operations but do not generate electricity during operations, therefore the net electricity generation for these facilities (electricity generation minus electricity consumption) for the No Action Alternative is negative for both long-term average and Dry and Critically Dry Water Years.
Units for this table are noted in Column 1 for all rows. Different rows in this table have different units (e.g., the first-row units are MW, the second and third row units are GWh, fourth row units are in percent, etc.); therefore, units are not included in the table headers.

17.4.2. Petroleum Products

17.4.2.1. Construction

The consumption of petroleum-based fuels for construction of the Project was estimated, including operation of construction equipment and vehicles for a period of approximately 6 years (2024 to 2029). Air quality/GHG emissions modeling estimated the GHG emissions from fuel (gasoline, diesel fuel) consumption for construction of Alternatives 1, 2, and 3. Air quality and GHG modeling methods, assumptions, and results are described in Chapter 20, *Air Quality*, and Chapter 21, *Greenhouse Gas Emissions*. Modeled GHG emissions from construction equipment operation were converted to construction equipment fuel consumption in units of gallons per year by assuming that 90% of the fuel consumed for construction equipment operation would be diesel fuel and that the remainder would be gasoline, based on use of standard construction equipment that primarily relies on diesel fuel. Conversion factors in units of GHG emissions per gallon of diesel fuel and per gallon of gasoline were applied to convert the modeled GHG emissions to diesel fuel gallons and gasoline gallons. GHG emissions were estimated for construction equipment based on the estimated operating hours for construction equipment anticipated to be used for Project construction.

Table 17-12a. Diesel Fuel and Gasoline Consumption for Construction of Alternatives 1, 2, and 3 (gallons per year and total gallons) for Construction Period

Alternative	Construction (max. gallons/year)		Construction (total gallons) for construction period	
	Gasoline	Diesel Fuel	Gasoline	Diesel Fuel
Alternatives 1 and 3	867,315	7,805,836	3,110,527	27,994,742
Alternative 2	1,031,008	9,279,071	3,135,427	28,218,840

Note: The construction footprint of Alternatives 1 and 3 would be identical. The maximum annual gasoline and diesel fuel consumption for construction over construction period duration would occur in 2026.

17.4.2.2. Operation

The consumption of petroleum-based fuels for operation of the Project was estimated. As for Project construction, fuel consumption for Project operations is based on GHG modeling results and conversion of the modeled GHG emissions to diesel fuel and gasoline consumption using conversion factors. The Project operating period modeled is from 2030–2040.

Operation of the Project includes facility and equipment maintenance activities. Many operation activities associated with monitoring and maintaining Project facilities would occur within the first 5 years (2030–2035) of Project operations. After the first 5 years of Project operation, scheduled operation (maintenance) activities would become less frequent, with some activities scheduled every 5 years and other activities scheduled at longer intervals (e.g., every 25 years). Diesel fuel and gasoline consumption for Project operation activities are based on modeled on-road vehicles and off-road equipment GHG emission factors by model year; GHG emissions are converted to fuel consumption using conversion factors. Off-road equipment GHG emission factors are only available in the GHG emissions model through model year 2040, and therefore the modeled Project operation period is from 2030–2040; modeling of Project GHG emissions past that timeframe would be considered speculative. On-road vehicles and off-road equipment are expected to become more fuel efficient over time, therefore the annual average operation and maintenance fuel consumption for the modeled 2030–2040 operating period is expected to be higher than annual average operations fuel consumption for subsequent operating years. The beginning of the operation period is modeled as 2030 because that is the earliest that Project operations would be expected to start following the end of the construction period. Diesel fuel and gasoline consumption for construction and operation of Alternatives 1, 2, and 3 are shown in Table 17-12a and Table 17-12b, respectively.

Table 17-12b. Diesel Fuel and Gasoline Consumption for Operation of Alternatives 1, 2, and 3 (gallons per year and total gallons) for 2030-2040 Modeled Operating Period

Alternative	Operation (max. gallons/year)		Operation (total gallons) 2030–2040	
	Gasoline	Diesel Fuel	Gasoline	Diesel Fuel
Alternatives 1 and 3	11,438	28,053	75,877	133,425
Alternative 2	11,866	25,948	77,134	125,011

Note: The maximum annual diesel fuel consumption for the modeled 2030–2040 operation period would occur in 2040. The maximum annual gasoline consumption for the modeled 2030–2040 operation period would occur in 2030.

17.5 Impact Analysis and Mitigation Measures

Impact EN-1: Potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources during construction or operation

No Project

There would be no change in energy consumption under the No Project Alternative because Project facilities would not be constructed or operated. Existing facilities including the RBPP and TC Canal, GCID Hamilton City Pumping Station and GCID Main Canal, and Funks Reservoir would continue to operate under the No Action Alternative. Energy consumption for these existing facilities would continue to be necessary for facility operations and maintenance. Wasteful, inefficient, or unnecessary energy consumption would therefore not occur under the No Project Alternative.

Significance Determination

Construction and operation of the Project would not occur, and the operation of existing facilities that are included in the No Action Alternative and the energy consumption of these facilities would not be affected. Energy consumption for these existing facilities would continue to be necessary for facility operations and maintenance. Therefore wasteful, inefficient, or unnecessary consumption of energy resources would not occur under the No Action Alternative. There would be no impact/no effect.

Alternatives 1 and 3

Construction

Petroleum Products

Construction of Alternatives 1 and 3 would require operation of diesel- and gasoline-fueled vehicles and equipment, including fuel consumption for operation of construction vehicles and construction equipment. The annual consumption of diesel fuel and gasoline for the construction period for Alternative 1 or 3 would be highest in 2026. In 2026 (i.e., the year of the highest annual anticipated consumption of construction fuel), construction of Alternatives 1 and 3 would require approximately 5.3% of the amount of diesel fuel consumed annually in the petroleum products study area and would require 0.5% of the amount of gasoline consumed annually in the petroleum products study area.

Construction equipment and construction vehicles used for construction of Alternative 1 or 3 would meet applicable federal and state standards for operation and fuel efficiency. GHG emissions modeling from which construction equipment and vehicle fuel consumption are derived is based on the assumption that on-road trucks used during the construction period would have engines certified to the 2010 model year or newer model year heavy-duty diesel engine air emissions standards. In addition, off-road construction equipment engines would meet Tier 4 engine standards, which was modeled. Equipment manufacturers have reported that Tier 4 engines are more fuel efficient than engines meeting previous tier standards, however, the Tier 4 engine standard is an air emissions standard, not a fuel efficiency standard, and fuel efficiency gains from application of Tier 4 engines would vary by engine type, engine manufacturer, and other factors, and therefore cannot be directly quantified. Mitigation Measure GHG-1.1: Achieve Net-Zero Emissions Through a GHG Reduction Plan would require near zero and zero emission vehicles to be used for construction, based on availability; given the current and anticipated limited availability of zero and near zero emissions construction equipment during the construction period, the potential fuel consumption effects of this GHG emissions mitigation measure have not been quantified.

The Authority will implement BMP-27 and Mitigation Measure GHG-1.1 to reduce construction GHG emissions. This BMP and mitigation measure will result in a corresponding decrease in energy consumption during construction. The fuel efficiency gains from application of this BMP and mitigation measure are subject to variability based on numerous factors, including availability of zero and near zero emissions construction equipment during the construction period, and therefore the reduction in fuel consumption from application of this BMP and mitigation measure cannot be quantified. However, application of this BMP and mitigation measure would result in gains in fuel efficiency. Therefore, construction of Alternative 1 or 3 would not result in wasteful, inefficient, or unnecessary consumption of energy resources.

Electricity

Electricity would be consumed during construction of Alternative 1 or 3 for construction area lighting and operation of electrical construction equipment and temporary construction facilities. Temporary electricity requirements for Alternatives 1 and 3 would be 10,300 kVA, equivalent to 17.8 MW (see Table 17-8). The construction period electricity requirements value of 17.8 MW assumes all of the electricity-consuming equipment and temporary facilities required for Project construction would be operating at the same time at 100% of full electricity demand. This is a conservative assumption, as the operation schedules of specific construction equipment and temporary facilities would vary during the construction period.

Based on the estimated hours of use (Table 17-8) of construction equipment and temporary construction facilities, annual electricity consumption for construction of Alternatives 1 and 3 would be 29 GWh per year. Annual electricity consumption for the four-county electricity supply study area in 2019 was 3,174.03 GWh, as shown in Table 17-5. Construction energy demand for Alternative 1 or 3 would correspond to 0.91% of the annual electricity consumption in the four-county study area.

Lighting and other electrical equipment and temporary facilities used for construction of Alternatives 1 and 3 would meet applicable energy efficiency standards, and their use would not result in wasteful, inefficient, or unnecessary consumption of energy resources. BMP-1 and BMP-27 applied to construction would reduce electricity consumption during the construction period. In accordance with BMP-1, the Authority will ensure conformance with applicable design standards and building codes for temporary construction facilities and equipment, including electrical generation equipment, substations, and transmission lines, buildings, and utility and infrastructure verification and/or relocation. Construction will conform to energy efficiency standards including but not limited to the California Energy Efficiency Standards for Residential and Nonresidential Buildings. For example, CCR Title 24 explicitly addresses building energy efficiency, and California's energy code is designed to reduce wasteful and unnecessary energy consumption in newly constructed and existing buildings. Therefore, construction of Alternative 1 or 3 would not result in wasteful, inefficient, or unnecessary consumption of energy resources.

Operations

Petroleum Products

Operations for Alternative 1 or 3 would require operation of maintenance, management, repair, and operating crew vehicles (including employee vehicles) and maintenance equipment. Operation of vehicles and maintenance equipment would involve consumption of gasoline and diesel fuel. Various types of fuel-consuming equipment would be necessary for maintenance of facilities, including for routine inspections and repairs. Users of the recreational facilities would travel to and from the reservoir in passenger vehicles and consume fuel as well.

Over the 2030–2040 modeled operating period, operation of Alternative 1 or 3 would consume 28,053 gallons of diesel fuel in the highest modeled operating year (2040) corresponding to 0.08% of the amount of diesel fuel consumed annually in the petroleum products study area and would consume 11,483 gallons of gasoline in the highest modeled operating year (2030), corresponding to 0.03% of the amount of gasoline consumed annually in the petroleum products study area. Equipment and vehicles used for operations activities for Alternative 1 or 3 would meet applicable federal and state standards for operations and fuel efficiency, and energy would be consumed for operations and maintenance-related activities and not for other purposes. Therefore, fuel would not be wasted through non-Project consumption. Operation and maintenance of Alternative 1 or 3 would not result in wasteful, inefficient, or unnecessary consumption of petroleum product energy resources.

Electricity

Operations under Alternative 1 or 3 would consume electricity for operation of pumps and other electrical equipment at the Funks and TRR East PGPs and also for the operation of Project administration and maintenance buildings. Title 24, Part 6, of the California Code of Regulations (*Energy Efficiency Standards for Residential and Nonresidential Buildings*) establishes the California Green Building Standards Code (CalGreen). The Counties of Colusa, Glenn, Tehama, and Yolo have adopted CalGreen energy efficiency standards for nonresidential structures in their building codes. The electricity consumption for the nonresidential structures associated with Alternative 1 or 3, including the PGPs and administration and maintenance buildings, would conform to the CalGreen standards incorporated in the applicable local codes. The Authority will implement BMP-1 to ensure conformance with applicable design standards and building codes for nonresidential buildings, equipment (e.g., electrical generation equipment, substations, and transmission lines), and utility and infrastructure verification and/or relocation, including but not limited to California Energy Efficiency Standards for Residential and Nonresidential Buildings.

Energy-efficient pumps and turbine generators would be used for the Funks and TRR East PGPs. Supplier-provided information indicated that the turbine efficiencies can be on the order of 94% at design operating conditions. Turbine efficiency would decrease during other operating conditions that differ from the design operating conditions. Hence, a conservative efficiency of 90% was used to estimate the amount of energy recovered by the turbines (Sites Project Authority 2020:5-8). Based on this assumption, less energy would be recovered by the turbines than the 94% turbine efficiency would indicate.

The pumps used for the Funks and TRR East PGPs would have a rated pump efficiency of 89% (Table 6:2-8 and Table 8:2-12 in Sites Project Authority 2020). The PGPs would each have separate pumping and generating units that would provide improved operability, and variable-speed pump drives would allow pumps to operate more efficiently than would constant-speed pumps (Sites Project Authority 2020:2-8). Pumps used for Project operations would meet applicable energy efficiency standards for clean water pumps under 10 CFR Subpart Y (10 CFR 431.461).

Alternative 1 or 3 electrical equipment, including pumping and generating equipment, and electrical equipment in buildings and other facilities would be designed and operated to conform to energy efficiency standards. Energy-efficient pumps would be used to transport water. U.S. Department of Energy standards for energy-efficient equipment in 10 CFR Subpart Y (10 CFR 431.462, *Energy Efficiency Program for Certain Commercial and Industrial Equipment Subpart Y. Pumps*) establishes energy efficiency standards for clean water pumps. The operation of nonresidential structures for Alternatives 1 and 3 would adhere to applicable energy efficiency standards. Therefore, operation of Alternative 1 or 3 would not result in wasteful, inefficient, or unnecessary consumption of electrical energy resources.

CEQA Significance Determination and Mitigation Measures

Electrical equipment used for construction and operation of Alternative 1 or 3 would meet federal and California standards. Gasoline and diesel fuel would be consumed in vehicles and equipment that would be used only for construction and operations and for no other purposes. Fuel would not be wasted through non-Project consumption. The operation of nonresidential structures for Alternatives 1 and 3 would adhere to applicable energy efficiency standards. Electrical and petroleum product energy resources required for Alternative 1 or 3 construction and operations activities would not be used inefficiently, wastefully, or unnecessarily. Construction and operations impacts on energy resources would be less than significant.

NEPA Conclusion

Construction and operations effects would be the same as described above for CEQA. The electrical equipment used during construction and operation of Alternative 1 or 3 would meet state and federal energy standards and the operation of nonresidential structures would not conflict with applicable energy efficiency standards as compared to the No Project Alternative. Alternative 1 or 3 would not result in wasteful, inefficient, or unnecessary consumption of electrical and petroleum project energy during construction and operation. Alternative 1 or 3 would have no adverse effects on energy resources during construction or operations.

Alternative 2

Construction

Petroleum Products

Construction of Alternative 2 would consume 6.3% of the amount of diesel fuel consumed annually in the petroleum products study area (more than the 5.3% for Alternatives 1 and 3) and would consume 0.6% of the amount of gasoline consumed annually in the petroleum products study area (more than the 0.5% for Alternatives 1 and 3) during the highest consumption construction year (2026). More diesel fuel would be used under Alternative 2 because of the construction of several facilities for Alternative 2 that would not be part of Alternatives 1 and 3 (e.g., South Road, longer Dunnigan Pipeline, and Sacramento River discharge). Alternatives 1 and 3 would include three additional saddle dams that would not be constructed under Alternative 2. Similar to Alternatives 1 and 3, construction of Alternative 2 would meet applicable federal and state standards for construction equipment and vehicle operation, BMP-27 and Mitigation Measure GHG-1.1: Achieve Net-Zero Emissions Through a GHG Reduction Plan applied to construction would result in improved equipment and vehicle fuel efficiency, and energy would be consumed for construction-related activities and not for other purposes. The construction of Alternative 2 therefore would not result in wasteful, inefficient, or unnecessary consumption of petroleum product energy resources.

Electricity

Electricity would be consumed during construction of Alternative 2. Construction equipment for Alternative 2 (see Table 17-8) would be as described above under Alternatives 1 and 3, except that the Cement Deep Soil Mixing Batch Plant would only be applicable to Alternatives 1 and 3. Electricity would be consumed during construction of Alternative 2 for construction area lighting and operation of electrical construction equipment and temporary construction facilities. Temporary electricity requirements for Alternative 2 would be 9,100 kVA, equivalent to 15.7 MW. As for Alternatives 1 and 3, the construction period electricity requirements value assumes that all of the electricity-consuming equipment and facilities for Project construction would be operating at the same time at 100% of full electricity demand. This is a conservative assumption, as the operation schedules of specific construction equipment and facilities during the construction period would vary during the construction period.

Based on the estimated hours of use (Table 17-8) of construction equipment and temporary construction facilities, annual electricity consumption for construction of Alternative 2 would be 26 GWh. Annual electricity consumption for the four-county electricity supply study area in 2019 was 3,174.03 GWh, as shown in Table 17-5. Project construction energy demand for Alternative 2 would correspond to 0.82% of the annual electricity consumption in the four-county study area.

Lighting and other electrical equipment used for construction of Alternative 2 would meet applicable energy efficiency standards, and their use would not result in wasteful, inefficient, or unnecessary consumption of energy resources. In accordance with BMP-1, the Authority will ensure conformance with applicable design standards and building codes for temporary construction facilities and equipment, including electrical generation equipment, substations, and transmission lines, buildings, and utility and infrastructure verification and/or relocation. Construction will conform to energy efficiency standards including but not limited to the California Energy Efficiency Standards for Residential and Nonresidential Buildings. Construction of Alternative 2 therefore would not result in wasteful, inefficient, or unnecessary consumption of electrical energy resources.

Operations

Similar to Alternative 1 or 3, the equipment and vehicles used for operation under Alternative 2 would meet applicable federal and state standards for operation. BMP-27 and Mitigation Measure GHG-1.1 would also improve fuel efficiency, and energy would be consumed for operations- and maintenance-related activities and not for other purposes. Therefore, fuel would not be wasted through non-Project consumption. Operation of Alternative 2 would not result in wasteful, inefficient, or unnecessary consumption of petroleum product energy resources.

As for Alternative 1 or 3, electrical equipment, including pumping and generating equipment and electrical equipment in buildings and facilities for Alternative 2 would be designed and operated to conform to energy efficiency standards. Energy-efficient turbines would be used to generate hydroelectricity for Alternative 2, and energy-efficient pumps would be used to transport water. Operation and maintenance of Alternative 2 would not result in wasteful, inefficient, or unnecessary consumption of electrical energy resources.

CEQA Significance Determination and Mitigation Measures

Electrical equipment and facilities used for construction, operations, and maintenance for Alternative 2 would meet federal and California standards, and facilities, vehicles, and equipment would be used only for construction and operations and maintenance needs and not for other purposes. Diesel fuel use would be higher under construction of Alternative 2 when compared to Alternative 1 or 3 due to the construction of several facilities for Alternative 2, including South Road, the longer Dunnigan Pipeline, and the Sacramento River discharge, that would not be constructed under Alternative 1 or 3. Energy resources required for Alternative 2 construction and operations activities would not be used inefficiently, wastefully, or unnecessarily. Construction and operations impacts would be less than significant.

NEPA Conclusion

Construction, operations, and maintenance effects would be the same as described above for CEQA. The electrical equipment used during construction and operation of Alternative 2 would meet state and federal energy standards and the operation of nonresidential structures would not conflict with applicable energy efficiency standards as compared to the No Project Alternative. Alternative 2 would not result in wasteful, inefficient, or unnecessary consumption of electrical and petroleum project energy during construction and operation. The construction and operation of Alternative 2 would have no adverse effects on energy resources.

Impact EN-2: Conflict with or obstruct a state or local plan for renewable energy or energy efficiency

No Project

No conflicts with or obstruction of a state or local plan for renewable energy or energy efficiency would occur under the No Project Alternative because construction and operation of the Project would not occur. There would be no change in energy consumption or renewable energy generation under the No Project Alternative. Existing facilities that would continue to be operated under the No Action Alternative would not be affected.

Significance Determination

Construction and operation of the Project would not occur, and existing facilities that would continue to be operated under the No Action Alternative would not be affected; therefore, the No Action Alternative would not conflict or obstruct with a state or local plan for renewable energy or energy efficiency. There would be no impact/no effect.

Alternatives 1, 2, and 3

Construction and Operations

Electricity

Federal and state regulations that apply in general to electricity generation and transmission include: WAPA regulations that apply to marketing and transmitting electricity from multiuse water projects; Public Utility Regulatory Policies Act (United States Code Title 16, Sections 2601–2645) regulations that obligate utilities to purchase renewable and higher-efficiency energy from independent producers; and California Public Utilities Commission (CPUC) regulations and California Independent System Operator (CalISO) regulations that apply to electricity generation and transmission (Chapter 4, *Regulatory and Environmental Compliance: Project Permits, Approvals, and Consultation Requirements*).

California Public Utilities Commission/California Independent System Operator

Electric transmission service would be required to support the PGP electricity requirements and to transmit the hydroelectric energy generated by the PGPs. Electric transmission service for the Project could be provided either by PG&E or through WAPA.

The electric transmission system in Northern California is owned largely by the federal government (through WAPA) and by PG&E. For PG&E, planned transmission system projects are identified during the CPUC and CalISO transmission planning process. The transmission system owner then seeks approval for the planned project through the appropriate regulatory authority, which for PG&E is the CPUC. As one of four power marketing agencies under the U.S. Department of Energy, WAPA has its own approval process for upgrading its transmission facilities.

The point of interconnection (POI) between the electrical substations and existing transmission lines would require that an application for interconnection request be submitted and processed under the relevant transmission operator interconnection process. The location of the POI to the WAPA or PG&E 230-kV transmission lines would depend on the results of the system impact study that would be completed by WAPA or by PG&E in conjunction with CalISO. Preparation of a system impact study requires that the proposed electric power generation project be at 60%–70% of complete design and takes approximately 2.5 years to complete. Based on the anticipated design and construction schedule, the system impact study would begin in spring of 2023. Typically, applicants have 7 years from the time of approval of the system impact study to intertie to the grid.

In the system impact study, WAPA or PG&E/CalISO would evaluate the proposed generation needs and the capacity of existing transmission facilities and equipment to accept the proposed new generation. Potential limitations of the existing grid and potential improvements to support the interconnection may be identified. This results in a system impact study report that identifies specific improvements needed and the cost of the necessary improvements. The applicant (i.e., the Authority) is typically responsible for paying for the cost of any necessary improvements to the existing grid to support the interconnection of the proposed new electric power generation project. The yet-to-be-completed system impact study for the Project in relation to either the PG&E or WAPA transmission system may show additional transmission system investments needed by the Project proponents to ensure reliable operation of the regional electric transmission system.

The system impact study, planning, and permitting process conducted by WAPA or by PG&E in conjunction with CalISO for Alternative 1, 2, or 3 would ensure that interconnection between the selected alternative's electrical generating equipment, substations, and pumping equipment and the existing electrical grid would not interfere with electric power transmission and would meet WAPA or PG&E and CalISO regulations and standards for interconnection to the existing electrical grid. In the event that the Authority determines that WAPA is to be the scheduling coordinator, WAPA would purchase electric power in the electricity markets on the Project's behalf and not affect CVP power.

California Energy Efficiency Standards (CalGreen)

Title 24, Part 6, of the California Code of Regulations (*Energy Efficiency Standards for Residential and Nonresidential Buildings*) establishes CalGreen. The Counties of Colusa, Glenn, Tehama, and Yolo have adopted these energy efficiency standards for nonresidential structures in their building codes. Nonresidential buildings that would be constructed for Alternative 1, 2, or 3 (e.g., PGPs, administration and maintenance buildings), would conform to the CalGreen standards incorporated in the applicable local codes.

Glenn County General Plan

Glenn County is updating the Glenn County General Plan (County of Glenn 2023:1). The Glenn County General Plan (1993) noted that the DWR has performed engineering feasibility studies for construction of reservoir and hydropower projects and anticipated that Glenn County should expect some aspects of previously studied projects to be proposed as state water resources become increasingly scarce (County of Glenn 1993a:23–24). The Energy Element of the 1993 Glenn County General Plan includes a policy to allow development of hydroelectric facilities while protecting the natural resources of the County from the potentially damaging effects of water storage and diversions for hydroelectric power generation (County of Glenn 1993b:119–120). Construction of Alternative 1, 2, or 3 would not conflict with this policy.

Design and Operation Standards

Alternatives 1, 2, and 3 would conform with applicable design standards and building codes for electrical generation, electrical supply, and transmission lines (BMP-1). The POI, transmission, and substation design criteria, depending on the POI option, would incorporate WAPA service and generation design criteria or incorporate PG&E interconnection requirements and PG&E substation design criteria. Transmission lines would be designed in accordance with California code and technical standards. Incorporation of the electrical supply and hydroelectric-generating capacity into the electrical grid would not conflict with or obstruct a state or local plan for renewable energy or energy efficiency.

Renewable Portfolio Standard

The California RPS (Senate Bill 350/Senate Bill 100) defines *large hydro projects* as those larger than 30 MW of hydroelectric generation capacity. Under the RPS definition, hydroelectric power generated from large hydro projects does not contribute to California RPS renewable energy targets. Hydroelectric power generated from the Funks PGP and TRR East (Alternatives 1 and 3) or TRR West PGP (Alternative 2) (each with a nameplate capacity of less than 40 MW) therefore would have no effect on the ability of California electricity providers to meet California's RPS renewable energy targets and would therefore not conflict with the renewable portfolio standard. California electricity providers are not relying on the incidental hydropower generation that would result from Project operations in order to meet their obligations under state or local plans for renewable energy or energy efficiency.

The Authority has established a target of purchasing at least 60% of the Project's operations power needs from renewable, carbon-free sources from the start of operations to 2045. Starting in 2045, the Authority will target purchasing 100% of the Project's operations power needs from renewable, carbon-free sources. This target does not include any operational power needs attributable to Reclamation's participation, including the conveyance and pumping of Incremental Level 4 Refuge water supply.

Petroleum Products

Appendix 4A, *Regulatory Requirements*, includes a description of federal and state regulations and Executive Orders that apply to energy and petroleum products. These would be applicable to petroleum products consumption during construction and operation of the Project. These include the following:

- National Corporate Average Fuel Economy Standards
- GHG Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
- California Assembly Bill 1493 – Vehicular emissions: greenhouse gases (2001–2002)
- Executive Order S-01-07 – Low Carbon Fuel Standard (LCFS) for transportation fuels

Construction and operation of the Project would not conflict with the above-listed energy and petroleum products regulations and Executive Orders. The Authority will comply with applicable regulations and Executive Orders for construction and operation of the Project and will apply BMP-27 and Mitigation Measure GHG-1.1: Achieve Net-Zero Emissions Through a GHG Reduction Plan which will have the effect of reducing petroleum product consumption for construction and operation of the Project.

CEQA Significance Determination and Mitigation Measures

Alternative 1, 2, or 3 construction, operations and maintenance would not conflict with state or local plans for energy efficiency or renewable energy and would conform to federal and state regulations and either WAPA standards or PG&E and CalISO standards for interconnection to the electric transmission system and operation of the electrical grid. Construction and operation of Alternative 1, 2, or 3 would result in no impact.

NEPA Conclusion

Construction, operations and maintenance effects associated with Alternative 1, 2, or 3 would be the same as described above for CEQA. Construction would not obstruct or conflict with state or local plans for renewable energy or energy efficiency, would comply with federal and state regulations, and would adhere to the applicable standards for interconnection to the existing electrical transmission system and operation of the electrical grid as compared to the No Project Alternative. Alternative 1, 2, or 3 would have no effect with respect to conflict with state or local plans and conformance to standards and regulations during construction. Operation of Alternative 1, 2, or 3 would result in generation of renewable hydroelectric power; however, renewable energy generated by Alternatives 1, 2, or 3 would be incidental to operations and would not contribute to California RPS renewable energy targets as compared to the No Project Alternative. Operations would also result in a reduction in net electricity generation for the CVP/SWP as a whole as compared to the No Project Alternative. While a net reduction may occur, the reduction would not conflict or obstruct renewable energy plans or energy efficiency. Therefore, no effects on renewable energy production and no conflicts with state or local plans for energy efficiency or renewable energy would occur.

Impact EN-3: Place a substantial demand on regional energy supply or require substantial additional capacity or substantially increase peak and base period electricity demand

No Project

No impacts on energy demand, supply, or capacity would occur under the No Project Alternative. There would be no change in energy consumption or energy generation because the Project would not be constructed and operated. Energy consumption of the existing facilities that would continue to be operated under the No Action Alternative would not be affected.

Significance Determination

Construction and operation of the Project would not occur, and there would be no substantial demand on a regional energy supply or the need for substantial additional capacity. Energy consumption of the existing facilities that would continue to be operated under the No Action Alternative would not be affected. There would be no impact/no effect.

Alternatives 1 and 3

Construction

Electricity

Consumption of electricity during construction of Alternatives 1 and 3 is not expected to require substantial additional electricity generation capacity or require additional electric transmission or distribution infrastructure, with the exception of connections between construction sites and the existing electrical distribution system. The Authority expects that Alternative 1 or 3 would obtain electricity from the electrical transmission grid (from PG&E and/or through WAPA) during the construction period. Temporary electricity requirements for Alternatives 1 and 3 would be 10,300 kVA, equivalent to 17.8 MW. Based on estimated hours of use (Table 17-8) of construction equipment and temporary construction facilities, annual electricity consumption for construction of Alternatives 1 and 3 would be 29 GWh per year. Annual electricity consumption for the four-county electricity supply study area in 2019 was 3,174.03 GWh, as shown in Table 17-5. Construction would require approximately 0.9% of the amount of electricity demand within the four-county electricity supply study area. Therefore, construction would not require substantial additional electric generation capacity, and existing transmission and distribution infrastructure is anticipated to be of sufficient capacity to supply electricity needed for construction.

Petroleum Products

Consumption of gasoline and diesel fuel during construction of Alternative 1 or 3 would not place a substantial demand on petroleum product energy supply or distribution infrastructure in the petroleum products study area. Consumption of these fuels would not place a substantial demand on regional energy supply because consumption would generally be temporary during construction and would be a small fraction of the gasoline and diesel fuel consumption in the petroleum products study area. Diesel fuel consumption and gasoline consumption for construction of Alternative 1 or 3 for 2026 and for the full construction period are presented in Table 17-12a (under Impact EN-1). Gasoline consumption for the year of the anticipated highest fuel consumption (2026) would be 0.5% of 2019 annual gasoline sales in the petroleum products study area for Alternatives 1 and 3. Diesel fuel consumption during the year of the anticipated highest fuel consumption would be 5.3% of 2019 annual diesel fuel sales in the petroleum products study area for Alternative 1 or 3. Alternative 1 or 3 would not place a substantial demand on regional energy supply because consumption would generally be temporary during construction, would be a small fraction of the current available supply, and would be satisfied by the available supply.

Operations

Petroleum Products

The volume of petroleum products used for operations and operation of passenger vehicles by recreational users of Project facilities would not place a substantial demand on regional energy supply or require substantial additional capacity. Gasoline and diesel fuel consumption for operation of Alternatives 1 and 3 are shown in Table 17-12b. Gasoline consumption for operations for Alternatives 1 and 3 would be 0.03% of annual gasoline consumption in the petroleum products study area over the modeled 2030–2040 operation period. Diesel fuel consumption for operation of Alternatives 1 and 3 would be 0.08% of annual diesel fuel consumption in the petroleum products study area over the modeled 2030–2040 operation period. Annual gasoline and diesel fuel consumption for operations in the highest year of the 2030–2040 modeled operating period would be less than annual gasoline and diesel fuel consumption for the highest year of the construction period (2026). Alternative 1 or 3 would not place a substantial demand on retail and nonretail petroleum products supply and would not require substantial additional capacity in the petroleum products study area to accommodate this increase in demand for operations. Construction equipment would be fueled on site, and fuel would be supplied by tanker trucks from wholesale diesel distributors. In general, large construction projects use tanker trucks or portable fuel tanks.

Electricity

Electricity required for pumping and for other equipment and facility operations would be procured from PG&E or through WAPA. Over a long-term average, Alternative 1 or 3 would be a net electricity consumer, not a net electricity generator. Alternative 1 or 3 would be a net generator of electricity during Dry and Critically Dry Water Years (see Tables 17-9 and 17-11).

Net electricity generation of the Project would be positive for Dry and Critically Dry Water Years because more releases of water from the Project would occur during Dry and Critically Dry Water Years.

As the Project storage and generation would be incorporated into the CVP/SWP system, Sites Reservoir would operate similarly to the CVP/SWP system as a whole, releasing more water during the summer months to meet summer water release demand and thereby generating more electric power during the summer months. Therefore, the Project would provide more electric generation in the summer months, when electricity demand is highest, as does the CVP/SWP system as a whole. The electricity modeling conducted for the Project considers the potential effects of the Project on electricity consumption and electricity generation for the entire CVP/SWP system, including the addition of the Project. Modeling results show that electric power production from the Project would be highest during the summer months when electricity demand is highest, and therefore the Project is not expected to substantially increase peak or base period electricity demand.

Table 17-13 summarizes the net reduction in CVP/SWP system (including the addition of the Project) electricity generation for each alternative as a percentage of statewide and regional electricity demand for long-term average and Dry and Critically Dry Water Years. The reduction in net electricity generation for Alternatives 1 and 3 would correspond to approximately 0.22% of regional (Northern California) electricity demand and approximately 0.13% of total in-state electricity generation for long-term average and would correspond to approximately 0.36% of regional electricity demand and 0.22% of total in-state electricity generation for Dry and Critically Dry Water Years.

Based on normal projected load growth and overall regional and statewide electricity generation, the net reduction in electricity generation for Alternatives 1 and 3 is not anticipated to require substantial additional electricity generation capacity in California. The approximately 0.13% reduction in long-term average net electricity generation for Alternatives 1 and 3 is expected to be replaced by modifications to existing California electricity generation facilities. A system impact study to be conducted by either PG&E/CalISO or WAPA, depending upon which electricity service provider is selected, would identify any necessary equipment upgrades to regional electric transmission facilities to support interconnection of the Project to the regional electrical grid. The timeframe for the system impact study is approximately 2023. Impacts on energy resources are further described below.

When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term average reduction in net electricity generation for the CVP/SWP system as a whole, including the addition of the Project, resulting from Alternatives 1A and 1B (Table 17-9; -265 GWh for Alternative 1A; -251 GWh for Alternative 1B) would correspond to 0.14% and 0.13% of total in-state electricity generation, respectively.

The reduction in net electricity generation during Dry and Critically Dry Water Years for the CVP/SWP system as a whole, including the addition of the Project, would correspond to 0.22% of total in-state electricity generation for Alternatives 1A and 1B (Table 17-9); -429 GWh for Alternative 1A; -420 GWh for Alternative 1B.

Addition of the Project to the CVP/SWP system would result in a 70.4% reduction in long-term average net electricity generation (-265 GWh) for the CVP/SWP system under Alternative 1A and would result in a 66.6% reduction in long-term average net electricity generation (-251 GWh) for the CVP/SWP system under Alternative 1B (see Table 17-9).

The reduction in long-term average net electricity generation of the CVP/SWP system (including the Project) for Alternative 1A (-265 GWh) and Alternative 1B (-251 GWh) as compared to the No Action Alternative would correspond to 0.23% and 0.22% of the total electricity demand in Northern California (115,940 GWh) (California Energy Commission 2020f:1-2). During Dry and Critically Dry Water Years, the reduction in net electricity generation for Alternative 1A (-429 GWh) and Alternative 1B (-420 GWh) as compared to the No Action Alternative for Dry and Critically Dry Water Years would correspond to 0.37% and 0.36% of the total electricity demand in Northern California (Table 17-9).

When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term average reduction in net electricity generation resulting from Alternative 3 (Table 17-11; -211 GWh) would correspond to 0.11% of total in-state generation. The reduction in net electricity generation during Dry and Critically Dry Water Years would correspond to 0.19% of total in-state electricity generation for Alternative 3 (Table 17-11; -362 GWh).

When compared to 2019 total electricity demand in Northern California (115,940 GWh) (California Energy Commission 2020f:1-2), the reduction in long-term average net electricity generation of the CVP/SWP system (including the Project) would correspond to approximately 0.18% of total electricity demand in Northern California for Alternative 3 (Table 17-11; -211 GWh). During Dry and Critically Dry Water Years, the reduction in net electricity generation would correspond to approximately 0.31% of total electricity demand in Northern California for Alternative 3 (Table 17-11; -362 GWh).

Table 17-13. Project Operations Electricity Demand and Net Reduction in CVP/SWP System Electricity Generation for Alternatives as Percentages of Statewide and Regional Electricity Demand

		No Action Alternative	Alternative 1A	Alternative 1B	Alternative 2	Alternative 3
Sites Reservoir Project Electricity Demand	Long-Term	12 GWh/year	94 GWh/year	97 GWh/year	88 GWh/year	104 GWh/year
	Dry and Critically Dry Water Years	11 GWh/year	41 GWh/year	40 GWh/year	40 GWh/year	40 GWh/year
Percent of Four-County Electricity Supply Study Area Electricity Demand	Long-Term	0.38%	3.0%	3.0%	2.7%	3.3%
	Dry and Critically Dry Water Years	0.35%	132%	1.3%	1.3%	1.3%
Change in CVP/SWP System Net Electricity Generation	Long-Term	0	-265 GWh/year	-251 GWh/year	-249 GWh/year	-211 GWh/year
	Dry and Critically Dry Water Years	0	-429 GWh/year	-420 GWh/year	-412 GWh/year	-362 GWh/year
Percent Change in CVP/SWP System Net Electricity Generation	Long-Term	---	-70.4%	-66.6%	-66.0%	-55.9%
Percent Change in CVP/SWP System Net Electricity Generation	Dry and Critically Dry Water Years	---	-1,135%	-1,501%	-1,471%	-1,293%
Percent of In-State Electricity Generation	Long-Term	---	0.14%	0.13%	0.13%	0.11%
	Dry and Critically Dry Water Years	---	0.22%	0.22%	0.21%	0.19%
Percent of Northern California Energy Demand	Long-Term	---	0.23%	0.22%	0.21%	0.19%
	Dry and Critically Dry Water Years	---	0.37%	0.36%	0.36%	0.31%
Total In-State Electricity Generation (2019)	194,842 GWh/year	---	---	---	---	---
Northern California Energy Demand (2019)	115,940 GWh/year	---	---	---	---	---
Four-County Electricity Supply Study Area Electricity Demand (2019)	3,174 GWh/year	---	---	---	---	---

Electricity consumption for operation of Alternative 1 or 3 Project facilities and equipment would include electricity consumption for operation of pumps and for administration and maintenance buildings. Alternative 1A electricity consumption would be 94 GWh per year for the long-term average and 41 GWh per year for Dry and Critically Dry Water Years (Table 17-9). Alternative 1B electricity consumption would be 97 GWh per year long-term average and 40 GWh per year for Dry and Critically Dry Water Years (Table 17-9).

Alternatives 1A and 1B electricity consumption for operation of Project facilities and equipment would represent 3.0% of regional electricity demand in the four-county electricity supply study area for long-term average operation and 1.3% of regional electricity demand in the four-county electricity supply study area for Dry and Critically Dry Water Years.

Electricity consumption for operation of Alternative 3 Project facilities and equipment would include electricity consumption for operation of pumps and for administration and maintenance buildings. Alternative 3 electricity consumption would be 104 GWh per year for long-term average operation and 40 GWh per year for Dry and Critically Dry Water Years (Table 17-11). Alternative 3 electricity consumption would represent 3.3% of regional electricity demand in the four-county electricity supply study area for long-term average operation and 1.3% of regional electricity demand in the four-county electricity supply study area for Dry and Critically Dry Water Years.

Based on normal projected load growth and overall regional and statewide electricity generation, the net reduction in electricity generation for Alternatives 1 and 3 is not anticipated to require substantial additional electricity generation capacity in California or place a substantial demand on regional energy supply.

A system impact study would be conducted by either PG&E/CalISO or WAPA, depending upon which electricity service provider is selected for the Project. The system impact study, expected to be conducted in the 2023 timeframe, would identify any necessary equipment upgrades to regional electric transmission facilities to support interconnection of the Project to the regional electrical grid. Until a system impact study conducted either by PG&E in conjunction with CalISO or by WAPA is undertaken, it is not possible to determine whether Project proponents would be required to invest in additional electric transmission infrastructure to ensure reliable operation of the existing regional transmission system. Based on current knowledge, operation of Alternatives 1 and 3 would not require substantial additional electric generation capacity.

CEQA Significance Determination and Mitigation Measures

Construction and operation of Alternative 1 or 3 would not place a substantial demand on regional energy supply, require substantial additional capacity, or substantially increase peak and base period electricity demand. Alternative 1 or 3 construction would require approximately 0.9% of the electricity demand within the four-county electricity supply study area. Therefore, construction of Alternative 1 or 3 would not place a substantial demand on regional electricity supply, require substantial additional capacity, or substantially increase peak and base period electricity demand. Gasoline consumption for the year of the anticipated highest fuel consumption (2026) for Alternatives 1 and 3 would be 0.5% of 2019 annual gasoline sales in the petroleum products study area for Alternatives 1 and 3. Diesel fuel consumption during the year of the anticipated highest fuel consumption would be 5.3% of 2019 annual diesel fuel sales in the petroleum products study area for Alternative 1 or 3. Therefore, Alternative 1 or 3 construction would not place a substantial demand on petroleum products supply or require substantial additional gasoline and diesel fuel capacity.

Electricity demand for Alternative 1 or 3 operations would not place a substantial demand on regional energy supply, require substantial additional capacity, or substantially increase peak and base period electricity demand. Alternatives 1A and 1B electricity consumption for operation of Project facilities and equipment would represent 2.9% of electricity demand in the four-county electricity supply study area for long-term average operation and 1.2% of electricity demand in the four-county electricity supply study area for Dry and Critically Dry Water Years. Alternative 3 electricity consumption would represent 3.2% of electricity demand in the four-county electricity supply study area for long-term average operation and 1.2% of electricity demand in the four-county electricity supply study area for Dry and Critically Dry Water Years. Substantial additional electricity generation capacity is not anticipated to be required to supply electricity for Project operations. Construction and operations impacts would be less than significant.

NEPA Conclusion

Construction and operation effects for Alternatives 1 and 3 would be the same as those described above for CEQA. The electricity consumption for construction of Alternative 1 or 3 would require approximately 0.9% of regional electricity demand, and the electricity consumption for Project operations would represent approximately 3.2% of regional electricity demand, as compared to the No Project Alternative. The highest anticipated gasoline and diesel fuel consumption would be in 2026 and would represent 0.5% of 2019 annual gasoline sales and 5.3% of 2019 annual diesel fuel sales as compared to the No Project Alternative. There would be no adverse effect on regional energy resources from construction or operation of Alternative 1 or 3. Electric power would generally be generated by the Project in the summer months when water is released to meet water demand as compared to the No Project Alternative. Considering the expected incidental and seasonal generation of renewable electricity from the Project and the net reduction in system-wide generation for the CVP/SWP system that would result from incorporation of the Project into the CVP/SWP system, there is no benefit to regional energy resources from generation of renewable energy as compared to the No Project Alternative. The operation of Alternative 1 or 3 would have no effect on regional energy resources from increased generation of renewable energy.

Alternative 2

Construction

Electricity

Consumption of electricity during construction of Alternative 2 is not expected to require substantial additional electric generation capacity or require additional electric transmission or distribution infrastructure, with the exception of connections between construction sites and the existing electrical distribution system. The Authority expects that Alternative 2 would obtain electric power from the electrical grid (from PG&E and/or through WAPA) during the construction period. Temporary electricity requirements for Alternative 2 would be 9,100 kVA, equivalent to 15.7 MW. Based on estimated hours of use (Table 17-8) of construction equipment and temporary construction facilities, annual electricity consumption for construction of Alternative 2 would be 26 GWh per year. Annual electricity consumption for the four-county electricity supply study area in 2019 was 3,174.03 GWh, as shown in Table 17-5, corresponding to 0.8% of regional electricity demand. As Alternative 2 would require a less than 1% of the amount of electricity distributed within the four-county electricity supply study area, Alternative 2 would not require substantial additional electricity generation capacity, and existing transmission and distribution infrastructure is anticipated to be of sufficient capacity to supply electricity needed for construction.

Petroleum Products

Diesel fuel consumption for construction of Alternative 2 for 2026 and for the full construction period are presented in Table 17-12a and described in Impact EN-1. Gasoline consumption would be 0.5% of 2019 annual gasoline sales in the petroleum products study area for Alternative 2 for the year anticipated to have the highest fuel consumption (2026). Diesel fuel consumption would be 6.3% of 2019 annual diesel fuel sales in the petroleum products study area for Alternative 2 for the highest fuel consumption year. The consumption of petroleum products would be slightly higher under Alternative 2 than under Alternatives 1 and 3 due to the construction of additional facilities for Alternative 2 that would not be constructed under Alternatives 1 and 3. Similar to impacts associated with Alternatives 1 and 3, consumption of gasoline and diesel fuel during the construction of Alternative 2 would not require substantial additional petroleum product capacity, and construction of Alternative 2 would not place a substantial demand on energy supply or distribution infrastructure in the petroleum products study area. Alternative 2 would not place a substantial demand on regional energy supply because consumption would generally be temporary during construction, would be a small fraction of the current available supply, and would be satisfied by the available supply.

Operations

Petroleum Products

Gasoline and diesel fuel consumption for operation of Alternative 2 is shown in Table 17-12b. Alternative 2 would consume 25,948 gallons of diesel fuel in the highest modeled operating year (2040) and would consume 11.866 gallons of gasoline in the highest modeled operating year (2030). Diesel fuel consumption for Alternative 2 operations would be almost the same as that for Alternatives 1 and 3, corresponding to 0.07% of annual diesel fuel consumption in the petroleum products study area for the 2030–2040 operations period. Gasoline consumption for Alternative 2 operations would be approximately the same as that for Alternatives 1 and 3, corresponding to 0.03% of annual gasoline consumption in the petroleum products study area for the modeled 2030–2040 operations period. As for Alternatives 1 and 3, equipment and vehicles used for operation of Alternative 2 would meet applicable federal and state standards for operation and fuel efficiency. The negligible volume of fuel and gasoline used for operation of Alternative 2 would not place a substantial demand on regional energy supply or require substantial additional capacity.

Electricity

Electricity required for pumping and for other Project equipment and facility operations would be procured from PG&E or through WAPA. Considering the modeled electricity demand and modeled electricity generation, Alternative 2 would be a net electricity consumer, not a net electricity generator, for long-term average operation. Alternative 3 would be a net electricity generator during Dry and Critically Dry Water Years.

Table 17-13 summarizes the net reduction in CVP/SWP system electricity generation for each alternative as a percentage of statewide and regional electricity demand for long-term average and Dry and Critically Dry Water Years. The net reduction in electricity generation for Alternative 2 would correspond to approximately 0.21% of regional (Northern California) electricity demand and approximately 0.13% of total in-state electricity generation for long-term average and would correspond to approximately 0.36% of regional electricity demand and 0.22% of total in-state electricity generation for Dry and Critically Dry Water Years.

Based on normal projected load growth and overall regional and statewide electricity generation, the net reduction in electricity generation for Alternative 1 is not anticipated to require substantial additional electricity generation capacity in California. The approximately 0.13% reduction in long-term average net electricity generation for Alternative 2 is expected to be replaced by modifications to existing California electricity generation facilities. A system impact study to be conducted by either PG&E/CalISO or WAPA, depending upon which electricity service provider is selected, would identify any necessary equipment upgrades to regional electric transmission facilities to support interconnection of the Project to the regional electrical grid.

Net electricity generation for Alternative 1A and Alternative 1B would be lower than that of Alternative 2 for long-term average operation, and net electricity generation for Alternative 1A and Alternative 1B would be lower than for Alternative 2 for Dry and Critically Dry Water Years (see Table 17-9, Table 17-10, Table 17-11, and Table 17-13). Net electricity generation for Alternative 3 for Dry and Critically Dry Water Years would be higher than for Alternative 1 or Alternative 2 (see Table 17-9, Table 17-10, Table 17-11, and Table 17-13).

The modeled CVP, SWP, and Project net electricity generation under Alternative 2 (electricity use minus electricity generation) would be 249 GWh less than the No Action Alternative over the long term and 412 GWh less than the No Action Alternative during Dry and Critically Dry Water Years (Table 17-10). Addition of the Project to the CVP/SWP system under Alternative 2 would result in a 66.0% reduction in long-term net electricity generation (-249 GWh) for the CVP/SWP system (see Table 17-10).

When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term reduction in net electricity generation resulting from Alternative 2 would correspond to 0.13% of total in-state generation. The reduction in net electricity generation during Dry and Critically Dry Water Years would correspond to 0.21% of total in-state generation for Alternative 2. These reductions in net electricity generation compared to total in-state generation are approximately the same as the results for Alternative 1 and higher than the results for Alternative 3 previously presented.

When compared to 2019 total electricity demand in Northern California (115,940 GWh) (California Energy Commission 2020f:1-2), the long-term net electricity generation would correspond to approximate 0.21% of Northern California electricity demand for Alternative 2. During Dry and Critically Dry Water Years, the net reduction would correspond to approximately 0.36% of Northern California electricity demand for Alternative 2. These reductions in net electricity generation compared to total electrical demand are also approximately the same as the results for Alternatives 1 and higher than the results for Alternative 3 presented above.

Alternative 2 electricity consumption would be 88 GWh per year for long-term operation and 40 GWh per year for Dry and Critically Dry Water Years (Table 17-10). Alternative 2 electricity consumption would represent 2.7% of regional electricity demand for the four-county electricity supply study area for long-term operation and 1.3% of regional electricity demand for the four-county electricity supply study area for Dry and Critically Dry Water Years.

Until a system impact study conducted either by PG&E in conjunction with CalISO or by WAPA is undertaken, it is not possible to determine whether Project proponents would be required to invest in additional electric transmission infrastructure to ensure reliable operation of the existing regional electric transmission system. Based on current knowledge, operation of Alternative 2 would not require substantial additional electric generation capacity.

CEQA Significance Determination and Mitigation Measures

Construction of Alternative 2 would result in energy resource impacts similar to those for Alternatives 1 and 3. However, the electricity consumption for Project construction would be higher for Alternatives 1 and 3 than for Alternative 2, and fuel consumption for Alternatives 1 and 3 would be lower than for Alternative 2. Electricity demand for construction and operations under Alternative 2 would not place a substantial demand on regional energy supply, require substantial additional capacity, or substantially increase peak and base period electricity demand. Alternative 2 electricity consumption for operations would represent 2.7% of electricity demand in the four-county electricity supply study area for long-term average operation and 1.3% of electricity demand in the four-county electricity supply study area for Dry and Critically Dry Water Years. Substantial additional electricity generation capacity is not anticipated to be required to supply electricity for Project construction and operations under Alternative 2. Construction and operations impacts would be less than significant.

NEPA Conclusion

Construction effects and operations effects for Alternative 2 would be the same as those described above for CEQA. The electricity consumption for construction of Alternative 2 would require approximately 0.6% of regional electricity demand, and the electricity consumption for Project operations would represent approximately 2.0% of regional electricity demand, as compared to the No Project Alternative. The highest anticipated gasoline and diesel fuel consumption would be in 2026 and would represent 0.6% of 2019 annual gasoline sales and 6.3% of 2019 annual diesel fuel sales as compared to the No Project Alternative. There would be no adverse effect on regional energy resources from construction or operation of Alternative 1 or

3. The operation of Alternative 2 would have no effect on regional energy resources from increased generation of renewable energy.

17.6 References

17.6.1. Printed References

California Energy Commission. 2019. *2018 Total System Electric Generation*. Last revised: June 24, 2019. Available: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2019-total-system-electric-generation/2018. Accessed: January 6, 2021.

California Energy Commission. 2020a. *2019 Total System Electric Generation*. Last revised: 2020. Available: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2019-total-system-electric-generation. Accessed: December 31, 2020.

California Energy Commission. 2020b. *Hydroelectric Power*. Last revised: 2020. Available: https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/hydroelectric-power. Accessed: February 16, 2023.

California Energy Commission. 2020c. CEC-1304 Power Plant Owners Report as of April 29, 2020. Available: https://www.energy.ca.gov/sites/default/files/2020-05/2019_capacity_and_Energy_ADA.xlsx.

California Energy Commission. 2020d. *Electricity* Consumption by County. Available: http://www.ecdms.energy.ca.gov/elecbycounty.aspx. Accessed: January 6, 2021.

California Energy Commission. 2020e. *Electricity Consumption by County*. Available: http://www.ecdms.energy.ca.gov/elecbycounty.aspx . Accessed: December 31, 2021.

California Energy Commission. 2020f. *2019 California Annual Retail Fuel Outlet Report Results (CEC-A15) Energy Assessments Division 09-22-20*. California Energy Commission, Supply Analysis Office. September 22, 2020. Available: https://www.energy.ca.gov/sites/default/files/2020-10/2010-2019%20CEC-A15%20Results%20and%20Analysis.xlsx. Accessed: January 12, 2021.

California Energy Commission. 2021. *California Hydroelectric Statistics and Data*. Last revised: 2021. Available: https://data.ca.gov/dataset/hydroelectric-energy/resource/7028fce4-7953-4139-afe5-0fb7fcc574ec. Accessed: January 6, 2021.

California Independent System Operator. 2020. *CAISO 2020 Summer Loads and Resources Assessment.* May 15, 2020. Available: https://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf. Page 32. Accessed: January 6, 2021.

County of Glenn 1993a. *Glenn County General Plan Volume II. Natural Resources issue Paper*. Prepared for Glenn County Board of Supervisors. Prepared by QUAD Consultants, Brow-Buntin Associates, Inc., Dowling Associates. 1993. Available: https://www.countyofglenn.net/sites/default/files/images/2%20Issue%20Papers%20Glenn%20County%20General%20Plan%20Vol.%20II%20Reduced%20Size.pdf. Accessed: January 14, 2021.

County of Glenn. 1993b. *Glenn County General Plan, Energy Element*. Prepared by Crawford Multari & Starr, 1993. Available: https://www.countyofglenn.net/sites/default/files/Planning/EnergyElement.pdf. Accessed: January 14, 2021.

County of Glenn. 2023. *Glenn County General Plan Update*. Available: https://glenncounty.generalplan.org/.

Holt. 2010. *Tier 4 Emissions Regulations*. Holt Caterpillar. Available: https://www.holtcat.com/Portals/0/Tier%204%20Emissions%20Info%20Page.pdf . Accessed: June 18, 2021.

National Oceanic and Atmospheric Administration. 2021. *Current U.S. Drought Monitor Conditions for California*. Available: https://www.drought.gov/states/california . Accessed: June 14, 2021.

Power Engineering. 2011. *Tier 4 Regulations Affect More than Engines*. June 1, 2011. Available: https://www.power-eng.com/emissions/air-pollution-control-equipment-services/tier-4-regulations-affect-more-than-engines/#gref. Accessed: June 14, 2021.

Sites Project Authority. 2020. *Final Feasibility Level Basis of Design Report – HC Conveyance Facilities, Sites Reservoir Project*. November 9, 2020.

17.6.2. Personal Communications

Garcia, Cary. California Energy Commission, Sacramento, CA. April 12, 2021—Email to Robert Lanza, Chemical Engineer Principal, ICF, Takoma Park, MD.