Chapter 17 Energy

Outstanding issues [yellow=info needed for completion from ICF or Integration; blue=QA/QC globals for ICF Editing]
Integration/Authority: Revised Sacramento Discharge structure for Alternative 2 is not in this chapter. Preliminary information about the design of this structure was received on 4/23 and GIS files came after 4/27. We would not expect determinations to change as a result of the revisions to the design; however, impact analysis will need to be reviewed/potentially modified to account for the revisions.

17.1 Introduction

This chapter describes the environmental setting, methods of analysis, and impact analysis for energy resources that would potentially be affected by the construction and operation of the Project. Energy resources are defined as electricity and fuels (gasoline, diesel fuel) and energy infrastructure, including the electric power grid and petroleum product distribution. The study area for energy resources for construction impacts and the study area for petroleum products consumption for operations consists of Glenn, Colusa, Sutter, Tehama, Yolo, and Yuba Counties. This study area is used because petroleum products consumed for construction are expected to come from counties where Project construction would occur (Glenn, Colusa, Tehama, and Yolo Counties) and from adjacent counties, including fuel consumed for transport of materials (e.g., sand and gravel) and construction debris (facilities in Sutter and Yuba Counties). The energy resources study area for operations impacts for electricity consumption consists of CVP/SWP operations, including CVP/SWP electricity generation and electricity consumption and also statewide electricity generation. Tables 17-1a and 17-1b summarize the CEQA determinations and NEPA conclusions for construction and operations impacts, respectively, for 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

Alternative	Level of Significance Before Mitigation	Mitigation Measures	Level of Significance After Mitigation
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 determination of no impact
LTS = CEQA determination of less-than-significant impact
LTSM = CEQA determination of less than significant with mitigation
SU = CEQA determination of significant and unavoidable
B = NEPA conclusion of beneficial effects
NE = NEPA conclusion of no effect or no adverse effect
AE = NEPA conclusion of adverse effect
SA = NEPA conclusion of substantial 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/B	-	NI/B
Alternative 2	NI/B	-	NI/B
Alternative 3	NI/B	-	NI/B
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 (without a system impact study, may not be able to conclusively answer the question whether the impact is going to be significant to other users on the PG&E or WAPA transmission system. Once the final alternatives have been definitively identified and system impact study conducted, then and only then can a determination be made whether the existing system can handle the load of the new project, or whether additional funds must be spent to reinforce the existing regional transmission system to ensure reliable operations.			

Alternative	Level of Significance Before Mitigation	Mitigation Measures	Level of Significance After Mitigation
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 determination of no impact
LTS = CEQA determination of less-than-significant impact
LTSM = CEQA determination of less than significant with mitigation
SU = CEQA determination of significant and unavoidable
B = NEPA conclusion of beneficial effects
NE = NEPA conclusion of no effect or no adverse effect
AE = NEPA conclusion of adverse effect
SA = NEPA conclusion of substantial 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 connected by high-voltage electric transmission lines and lower-voltage distribution lines. Table 17-2a and Table 17-2b show the breakdown of sources for electric generation in the state in 2018 and 2019, respectively. Table 17-3 shows electric generation in the state by fuel type. Total system electric generation is the sum of all utility-scale in-state generation plus net electricity imports. In 2019, total generation for California was 277,704 gigawatt-hours (GWh), down 2.7% (7,784 GWh) from 2018. California produces approximately two-thirds of its electricity from sources within the state. Approximately one-third of California's electricity supply is imported from the Pacific Northwest and the Southwest. In 2019, the total electricity imported was 130,528 GWh, up from 90,647 GWh in 2018 (California Energy Commission 2020a:1, 2020b: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). The gain from hydroelectric generation was offset by a 15% decrease in net imports to 77,229 GWh, 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 electric generation in 2018 and 57% in 2019 (California Energy Commission 2020a:1, 2020b:1). Note: Diablo Canyon, California's last nuclear powered generating station is scheduled to close on or about 2024. , Total electric energy 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 to meet the 60% California renewable energy requirement by 2030 (California Independent System Operator 2020:32).

Hydroelectric power in California is divided into two categories: large hydro, which is defined as facilities larger than 30 megawatts (MW), and small hydro, which includes all other facilities. Small hydroelectric plants qualify as renewable energy under the Renewables Portfolio Standard (RPS); certain hydroelectric plants larger than 30 MW also qualify under specific provisions of the RPS (California Energy Commission 2020c:1). In 2019, hydro-produced electricity used by California totaled approximately 38,494 GWh, or 19.21% of California's in-state generation portfolio. 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 2020d:1).

Table 17-2a. 2019 Total System Electric 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 (%)
2019 Total System Electric Generation						
Nonrenewables						
Coal	248	0.12%	219	7,765	7,985	10.34%
Natural Gas	86,136	42.97%	62	8,859	8,921	11.55%
Oil	36	0.02%	0	0	0	0.00%
Other[2]	411	0.20%	0	11	11	0.01%
Nuclear	16,163	8.06%	39	8,743	8,782	11.37%
Large Hydro[3]	33,145	16.53%	6,387	1,071	7,458	9.66%
Unspecified Sources of Power[4]	0	0.00%	6,609	13,767	20,376	26.38%
Nonrenewables and Unspecified Totals	136,139	67.91%	13,315	40,218	53,533	69.32%
Renewables[5]						
Biomass	5,851	2.92%	903	33	936	1.21%
Geothermal	10,943	5.46%	99	2,218	2,318	3.00%
Small Hydro[6]	5,349	2.67%	292	4	296	0.38%
Solar	28,513	14.22%	282	5,295	5,577	7.22%
Wind	13,680	6.82%	9,038	5,531	14,569	18.87%
Renewables Totals	64,336	32.09%	10,615	13,081	23,696	30.68%
System Total	200,475	100.00%	23,930	53,299	77,229	100.00%

Source: California Energy Commission 2020a :1, 2020b :1

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 17-2b. 2018 Total System Electric 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 Electric 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%

Source: California Energy Commission 2020a:1, 2020b:1

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 Electric 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 2021
Notes:
GWh = gigawatt-hours.

17.2.1.2. Electricity Demand

California's peak electricity load was 46,236 MW in 2020 (California Independent System Operator 2021:1). Electricity demand for the mid-case energy demand (2019) is projected to grow at an annual rate of 0.84% through 2030. Recent and projected growth trends are shown in Table 17-4 (California Energy Commission 2021:1).

Table 17-4. Comparison of CED 2019 and CEDU 2020 Low-, Mid-, and High-Case Demand Baseline—Statewide Consumption (GWh) and Net Peak Demand (MW)

Statewide Consumption (GWh)				
Year	***CED 2019* Mid-Energy Demand**	***CEDU 2020* Mid-Energy Demand**	***CEDU 2020* High-Energy Demand**	***CEDU 2020* Low-Energy Demand**
1990	225,241	227,599	227,599	227,599
2000	257,208	261,414	261,414	261,414
2010	272,919	272,693	272,693	272,693
2019	283,426	277,755	277,755	277,755
2020	285,326	273,516	276,563	270,688
2021	288,440	277,410	282,502	272,645
2023	296,235	290,951	298,880	283,031
2025	303,778	300,233	310,477	289,295
2030	321,284	317,217	333,784	299,054
Average Annual Growth Rates				
1990–2000	1.3%	1.4%	1.4%	1.4%
2000–2010	0.6%	0.4%	0.4%	0.4%
2010–2019	0.4%	0.2%	0.2%	0.2%
2019-2021	0.9%	-0.1%	0.9%	-0.9%
2019–2023	1.1%	1.2%	1.8%	0.5%
2019-2025	1.2%	1.3%	1.9%	0.7%
2019–2030	1.1%	1.2%	1.7%	0.7%
State Coincident Net Peak (MW)				
Year	***CED 2019* Mid-Energy Demand**	***CEDU 2020* Mid-Energy Demand**	***CEDU 2020* High-Energy Demand**	***CEDU 2020* Low-Energy Demand**
1990	47,120	47,120	47,120	47,120
2000	53,528	53,528	53,528	53,528
2010	62,069	62,069	62,069	62,069
2019	61,141	60,606	60,606	60,606
2020[a]	60,764	60,762	60,762	60,762
2021	60,495	60,879	61,614	60,203
2023	60,859	61,727	63,902	59,761
2025	61,445	62,583	65,574	59,968
2030	63,637	64,738	69,434	60,840
Average Annual Growth Rates				
1990–2000	1.3%	1.3%	1.3%	1.3%
2000–2010	1.5%	1.5%	1.5%	1.5%
2010–2019	-0.2%	-0.3%	-0.3%	-0.3%

2020–2021	-0.4%	0.2%	1.4%	-0.9%
2020–2023	0.1%	0.5%	1.7%	-0.6%
2020-2025	0.2%	0.6%	1.5%	-0.3%
2025–2030	0.5%	0.6%	1.3%	0.0%

Source: Garcia pers. comm.:1
Notes:
Actual historical values are shaded.
[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
The average annual growth rates can be compared and the net peak MW are comparable to one another.

17.2.1.3. Electricity Consumption

Annual electricity consumption for the six counties in the construction impacts study area in 2019 is shown in Table 17-5 (California Energy Commission 2020e:1). Total electricity consumption for the study area in 2019 was approximately 4,318 GWh, including 2,591 GWh (60%) of nonresidential consumption and 1,727 GWh (40%) of residential consumption.

Approximately 40% of the total electricity consumption for 2019 in the study area was in Yolo County in 2019; Tehama County represented approximately 18% of the total consumption. Annual electricity consumption for Northern California in 2019 was 115,240 GWh (California Energy Commission 2020f:1-2).

Table 17-5. Annual Electricity Consumption by County in 2019 (GWh)

County	Nonresidential	Residential	Total	Percent
Colusa	217.85	67.63	285.49	6.6%
Glenn	297.27	96.83	394.10	9.1%
Sutter	344.24	287.85	632.09	14.6%
Tehama	265.95	507.74	773.69	17.9%
Yolo	1,181.97	538.78	1,720.75	39.9%
Yuba	283.83	227.90	511.73	11.9%
Total	2,591.11	1,726.72	4,317.83	100.0%

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

17.2.2. Petroleum Products

Tables 17-6 and 17-7 show annual gasoline and diesel fuel sales for the study area for 2018 and 2019. Gasoline and diesel fuel sales data are reported annually by the California Energy Commission (CEC) Supply Analysis Office (California Energy Commission 2020g:1-2). Survey data are collected for retail gasoline sales and retail diesel fuel sales. The CEC Supply Analysis Office estimates that nonretail sales of diesel fuel are approximately 52.8% of retail sales.

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

County	2018	2019
Colusa	13	13

County	2018	2019
Glenn	17	18
Sutter	40	38
Tehama	31	30
Yolo	110	114
Yuba	46	32
Total	257	245

Source: California Energy Commission 2020g:1-2

Table 17-7. Annual Diesel Fuel Sales for 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
Sutter	5	5.6	6	6.7	10.6	12.7
Tehama	20	22.4	42.4	18	20.1	38.1
Yolo	28	31.3	59.3	26	29.1	55.1
Yuba	12	13.4	5	5.6	25.4	10.6
Total	86	96.2	81	90.6	182.2	171.6

Source: California Energy Commission 2020g:1-2

17.3 Modeling Results

17.3.1.1. Diesel Fuel/Gasoline Consumption

Air quality/greenhouse gas (GHG) emissions modeling estimated the GHG emissions from fuel (gasoline, diesel fuel) consumption for construction of Alternatives 1, 2, and 3. The air quality/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 standard use of equipment that primarily relies on diesel fuel. Conversion factors in units of GHG emissions per gallon of fuel were applied to convert the GHG emissions to diesel fuel gallons and gasoline gallons. Fuel consumption GHG emissions were estimated for construction equipment based on the estimated operating hours and average hourly fuel consumption for construction equipment anticipated to be used for construction of the alternatives.

Operation includes maintenance activities. Many operation activities associated with monitoring various facilities would occur within the first 5 years (2030–2035) of operations. After the first 5 years, operation activities would become more infrequent, with some activities scheduled every 5 years and other activities scheduled at longer intervals (e.g., every 25 years). Modeled diesel fuel and gasoline consumption for operation activities are based on on-road vehicles and off-road equipment fuel consumption factors by model year; off-road equipment fuel consumption factors are only available through model year 2040, and therefore modeling 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 the 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 phase. Diesel fuel and gasoline consumption for construction and operation of Alternatives 1, 2, and 3 are shown in Table 17-8a and Table 17-8b, respectively.

Table 17-8a. Diesel Fuel and Gasoline Consumption for Construction of Alternatives 1, 2, and 3 (gallons per year and total gallons)

Alternative	Construction (max. gallons/year)		Construction (total gallons)	
	Gasoline	Diesel Fuel	Gasoline	Diesel Fuel
Alternatives 1 and 3	908,323	8,174,906	3,276,275	29,486,474
Alternative 2	1,010,069	9,090,623	3,170,625	28,535,625

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

Table 17-8b. Diesel Fuel and Gasoline Consumption for Operation of Alternatives 1, 2, and 3 (gallons per year and total gallons)

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: Alternative 1A includes no Reclamation investment. Alternative 1B includes up to 7% Reclamation investment, which equates to about 91,000 AF of storage allocation dedicated to Reclamation in Sites Reservoir. 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.

17.3.1.2. Electricity Consumption

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 electricity requirements are provided for temporary facilities (e.g., contractor's and owner's office complex) and temporary construction material production sites (e.g., onsite quarries, concrete batch plants, asphalt batch plants), including for construction of reservoir dams, saddle dams, I/O structures, roads, and conveyance structures. Electricity requirements estimated in units of kVA are converted to electricity consumption in units of kilowatts (kW) in Table 17-9 to compare to the baseline electricity consumption for the study area.[1] Temporary electricity requirements for construction of Alternatives 1, 2, and 3 would be 8.500 kVA, equivalent to electricity consumption of 14,722 kW or 14.7 MW. Construction electricity consumption would

[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.

be the same for Alternatives 1, 2, and 3, with the exception of one Cement Deep Soil Mixing Batch Plant, which would only be applicable to Alternatives 1 and 3 and construction of TRR East.

Table 17-9. Temporary Electricity Requirements and Consumption for Construction of Alternatives 1, 2, and 3 (kVA and kW)

Location/Facility	Required Load, Three-Phase, kVA	Normalized kVA	kW	Annual Use (hours/year)
Golden Gate and Sites Dams				
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100
Golden Gate Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1,500
Sites Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1,500
Golden Gate Concrete Batch Plant	600	1,039.2	1,039.2	1,500
Sites Concrete Batch Plant	600	1,039.2	1,039.2	1,500
Contractor's Shop Complex	300	519.6	519.6	1,500
Saddle Dams				
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100
Saddle Dams Quarry Feeder/Jaw for Transition Zones	1,000	1,732.0	1,732.0	1500
Concrete Batch Plant	600	1,039.2	1,039.2	1,500
Contractor's Shop Complex	300	519.6	519.6	1,500
I/O Facilities				
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100
Concrete Batch Plant	600	1,039.2	1,039.2	1,500
Contractor's Shop Complex	200	346.4	346.4	1,500
Roads				
Contractor's and Owner's Office Complex	300	519.6	519.6	2,100
Asphalt Batch Plant	600	1,039.2	1,039.2	1,500
Contractor's Shop Complex	200	346.4	346.4	1,500
Conveyance				
Contractor's and Owner's Office Complex (3)	900	1,558.8	1,558.8	2,100
Concrete Batch Plant & CDSM Batch Plant (2)	1,200	2,078.5	2,078.5	1,500
Total	**10,300**	**17,839.4**	**17,839.4**	**-**

Source: Chapter 2, *Project Description and Alternatives*, Table 2-9
Note: Construction electricity requirements and electricity consumption are assumed to be the same for Alternatives 1, 2, and 3.
CDSM = Cement Deep Soil Mixing and only applicable to Alternatives 1 and 3; kVA = kilovolt-ampere; kW = kilowatt

Annual electricity generation and annual electricity consumption for operation are shown in Table 17-10 (Alternatives 1A and 1B), Table 17-11 (Alternative 2), and Table 17-12 (Alternative 3) in units of GWh/year, including CVP and SWP power facilities (electricity generation) and pumping facilities (electricity consumption). Total facility generating capacities (in 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 X, XXXX *Integration/Authority: here we would cite to the power appendix.*). Estimates of net electricity generation are provided for long-term conditions and Dry and Critically Dry Water Years.

Table 17-10. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1]—No Action Alternative, 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]	1,685	1,686	1,688	3	1
		Dry and Critically Dry Water Years[4]	1,589	1,590	1,593	4	2
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	4,694	4,696	4,697	3	2
		Dry and Critically Dry Water Years	3,419	3,417	3,422	4	-1
CVP Pumping Facilities							
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	1,333	1,336	1,339	6	3
		Dry and Critically Dry Water Years	1,100	1,103	1,110	9	3
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	1%	0%	0%	-1%	-1%
Total CVP Facilities							
Net Generation[5]	*Total of all Facilities (GWh)*	Long-Term	3,360	3,360	3,358	-2	-1
		Dry and Critically Dry Water Years	2,318	2,314	2,313	-6	-5
SWP Power Facilities							
Capacity	*Total of all Facilities at load center (GWh)*	Long-Term	982	995	994	12	13
		Dry and Critically Dry Water Years	631	643	646	15	12
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	3,936	4,037	4,028	91	101
		Dry and Critically Dry Water Years	2,555	2,739	2,738	183	184

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	6,919	7,254	7,224	305	334
		Dry and Critically Dry Water Years	4,901	5,562	5,557	657	661
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	-2,983	-3,217	-3,196	-213	-234
		Dry and Critically Dry Water Years	-2,345	-2,823	-2,819	-474	-477
Alternative 1 Power Facilities							
Capacity	*At load center (MW)*	Long-Term	0	4	5	5	4
		Dry and Critically Dry Water Years	0	7	7	7	7
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	38	40	40	38
		Dry and Critically Dry Water Years	0	64	63	63	64
Alternative 1 Pumping Facilities							
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	92	96	84	80
		Dry and Critically Dry Water Years	11	40	40	29	29
Total Alternative 1 Facilities							
Net Generation	Total of all Facilities (GWh)	Long-Term	-12	-54	-56	-44	-42
		Dry and Critically Dry Water Years	-11	24	23	34	35

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	365	89	105	-260	-276
		Dry and Critically Dry Water Years	-38	-485	-483	-445	-447
Net Generation	*Percent Change (GWh/GWh)*	Long-Term	–	–	–	--71.2%	-75.6%
		Dry and Critically Dry Water Years	–	–	–	-1,182%	-1,186%
Energy Use [7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	–	4.8%	5.0%
		Dry and Critically Dry Water Years	–	–	–	11.6%	11.5%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,265	8,682	8,659	395	417
		Dry and Critically Dry Water Years	6,011	6,705	6,707	695	694

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 and 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

Table 17-11. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1] —No Action Alternative and Alternative 2

Parameter		Long-Term Average or Dry and Critically Dry Water Year 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]	1,685	1,686	1
		Dry and Critically Dry Water Years[4]	1,589	1,590	2
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	4,694	4,695	2
		Dry and Critically Dry Water Years	3,419	3,418	-1
CVP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	1,333	1,336	2
		Dry and Critically Dry Water Years	1,100	1,103	3
Off-Peak Pumping Targets	*Percent of Time Off Peak Target Not Met (%)*	Long-Term	0%	0%	0%
		Dry and Critically Dry Water Years	1%	0%	-1%
Total CVP Facilities					
Net Generation[5]	*Total of All Facilities (GWh)*	Long-Term	3,360	3,360	-1
		Dry and Critically Dry Water Years	2,318	2,315	-4
SWP Power Facilities					
Capacity	*Total of All Facilities at Load Center (GWh)*	Long-Term	982	994	12
		Dry and Critically Dry Water Years	631	641	10
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	3,936	4,026	90
		Dry and Critically Dry Water Years	2,555	2,736	181
SWP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	6,919	7,217	298
		Dry and Critically Dry Water Years	4,901	5,538	637
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	-2,983	-3,191	-208
		Dry and Critically Dry Water Years	-2,345	-2,802	-456
Alternative 2 Power Facilities					
Capacity	*At load center*	Long-Term	0	4	4

Parameter		Long-Term Average or Dry and Critically Dry Water Year Average	NAA	Alternative 2	Difference between Alternative 2 and NAA[2]
	(MW)	Dry and Critically Dry Water Years	0	6	6
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	34	34
		Dry and Critically Dry Water Years	0	56	56
Alternative 2 Pumping Facilities					
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	85	73
		Dry and Critically Dry Water Years	11	38	27
Total Alternative 2 Facilities					
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-12	-51	-39
		Dry and Critically Dry Water Years	-11	18	29
All Facilities (CVP, SWP, and Alternative 2)[5, 6]					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	365	117	-248
		Dry and Critically Dry Water Years	-38	-469	-431
Net Generation	*Percent Change (GWh/GWh)*	Long-Term	–	–	-67.9%
		Dry and Critically Dry Water Years	–	–	-1,145%
Energy Use[7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	4.5%
		Dry and Critically Dry Water Years	–	–	11.1%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,265	8,639	374
		Dry and Critically Dry Water Years	6,011	6,678	667

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 and 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

Table 17-12. CVP, SWP, and Project Facilities Operation Energy Consumption (GWh/year)[1]—No Action Alternative and Alternative 3

Parameter		Long-Term Average or Dry and Critically Dry Water Year 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]	1,685	1,692	7
		Dry and Critically Dry Water Years[4]	1,589	1,599	10
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	4,694	4,696	2
		Dry and Critically Dry Water Years	3,419	3,427	8
CVP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	1,333	1,344	10
		Dry and Critically Dry Water Years	1,100	1,117	17
Off-Peak Pumping Targets	*Percent of Time Off Peak Target Not Met (%)*	Long-Term	0%	0%	0%
		Dry and Critically Dry Water Years	1%	0%	-1%
Total CVP Facilities					
Net Generation[5]	*Total of All Facilities (GWh)*	Long-Term	3,360	3,352	-8
		Dry and Critically Dry Water Years	2,318	2,309	-9
SWP Power Facilities					
Capacity	*Total of All Facilities at Load Center (GWh)*	Long-Term	982	994	11
		Dry and Critically Dry Water Years	631	645	14
Energy Generation	*Total of All Facilities at Load Center (GWh)*	Long-Term	3,936	4,010	74
		Dry and Critically Dry Water Years	2,555	2,714	159
SWP Pumping Facilities					
Energy Use	*Total of All Facilities at Load Center (GWh)*	Long-Term	6.919	7,167	248
		Dry and Critically Dry Water Years	4,901	5,447	547
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	-2,983	-3,157	-174
		Dry and Critically Dry Water Years	-2,345	-2,733	-388
Alternative 3 Power Facilities					
Capacity	*At load center*	Long-Term	0	5	5

Parameter		Long-Term Average or Dry and Critically Dry Water Year Average	NAA	Alternative 3	Difference between Alternative 3 and NAA[2]
	(MW)	Dry and Critically Dry Water Years	0	6	6
Energy Generation	*Total of all Facilities at load center (GWh)*	Long-Term	0	44	44
		Dry and Critically Dry Water Years	0	56	56
Alternative 3 Pumping Facilities					
Energy Use	*Total of all Facilities at load center (GWh)*	Long-Term	12	103	91
		Dry and Critically Dry Water Years	11	38	28
Total Alternative 3 Facilities					
Net Generation	*Total of all Facilities (GWh)*	Long-Term	-12		
		Dry and Critically Dry Water Years	-11		
All Facilities (CVP, SWP, and Alternative 3)[5, 6]					
Net Generation	*Total of All Facilities (GWh)*	Long-Term	365	136	-229
		Dry and Critically Dry Water Years	-38	-407	-369
Net Generation	*Percent Change (GWh/GWh)*	Long-Term	–	–	-62.6%
		Dry and Critically Dry Water Years	–	–	-979.4%
Energy Use [7]	*Total of all facilities (Percent Change)*	Long-Term	–	–	4.2%
		Dry and Critically Dry Water Years	–	–	9.8%
Energy Use	*Total of all facilities (GWh)*	Long-Term	8,265	8,613	349
		Dry and Critically Dry Water Years	6,011	6,603	592

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 and 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

17.4 Methods of Analysis

Energy production and energy consumption is evaluated in the context of energy that is used and energy that is generated during construction and operation. Alternatives are evaluated for expenditures of energy and if they would reduce production of renewable energy within the operations impacts study area. Alternatives are also evaluated to determine potential decreases in overall per capita energy consumption, decreases in reliance on fossil fuels, or increasing reliance on renewable energy sources.

17.4.1. Construction

BMPs have been incorporated into the construction impact analysis for energy resources. Descriptions of these BMPs are in Appendix 2D, *Best Management Practices*. In accordance with the BMP to Conform with Applicable Design Standards and Building Codes, the Authority would ensure conformance with applicable design standards and building codes for equipment, including electrical generation equipment, substations, and transmission lines and utility and infrastructure verification and/or relocation. In accordance with the BMP for Construction Best Management Practices to Reduce GHG Emissions, the Authority would implement measures to reduce construction GHG emissions and that would result in associated reduced construction energy consumption, which are discussed in detail in Appendix 4A, *Regulatory Requirements*.

The annual diesel fuel and gasoline consumption for Project construction is compared to the annual amounts of diesel fuel and gasoline consumed (based on sales data) in the study area for the construction period. Based on fuel consumption modeling, the peak year for petroleum products consumption during the construction period would be 2026. This year was selected for comparison of annual fuel demand to the annual petroleum products consumption in the study area because it represents the year of the highest diesel fuel and gasoline consumption over the duration of the anticipated construction period.

Construction energy consumption impacts include fuel consumption for construction of all facilities and fuel consumption for the use of haul trucks to transport construction materials and construction debris. Fuel would also be consumed for transport of construction workers to/from construction sites. Construction workers may come from areas outside of the study area, including the Sacramento area; the origins and numbers of construction worker vehicle trips are not included in the fuel consumption modeling because they are unknown.

A description of vehicles and construction equipment that would be used for construction is in Appendix 2C, *Construction Means, Methods, and Assumptions*. Construction energy impacts are evaluated for each alternative as a whole and assess the consumption of electricity. Electricity consumption for construction of the alternatives is compared to the amount of electricity consumed in the study area for construction impacts.

17.4.2. Operation

The analysis focuses on the potential impacts on electricity demand and production that could result from operation of Alternatives 1A, 1B, 2, and 3.

The BMP to Conform with Applicable Design Standards and Building Codes 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.

Diesel fuel and gasoline consumption for operation of the alternatives is compared to the amounts of diesel fuel and gasoline consumed in the study area for petroleum products consumption. Diesel fuel and gasoline consumption for operations and maintenance has been modeled for an operating period of 2030–2040.

The electric power grid in the Western Interconnection (made up of all or parts of 14 states, two Canadian provinces, and part of Mexico) is highly interconnected. Electricity generation operations under Alternatives 1, 2, and 3 would be incidental; the Project would generate electricity on an intermittent basis and would not generate more than 40 MW per facility based on design (i.e., Project facilities would not able to generate more than 40 MW). The increased electricity use under operating conditions is balanced against the beneficial attributes of the electricity generation provided by each alternative. Hydropower generation would be an incidental benefit of conveying water through specific Project facilities and would be influenced by the timing of releases, movement of water, and seasonal operational decisions. The Project would ultimately be a net user of electricity rather than a net generator of electricity. Operation of the Project, as described in Section 17.3, *Modeling Results*, would have a negligible effect on the statewide electric grid.

The energy consumption and production during operation would involve multiple facilities (e.g., Funks PGP, TRR West or TRR East PGP); interconnections to the existing electric power grid; and electricity generation and energy-consuming components of the CVP/SWP. Energy resource impacts are evaluated for each alternative, including a collective assessment of operation for all energy-consuming facilities and all energy-producing facilities in the study area for electricity consumption.

The net electricity consumption for operation of Alternatives 1A, 1B, 2, and 3 is compared to the No Action Alternative energy consumption for CVP and SWP facility operation, including generation and pumping. The 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 some electricity at generating stations along the California Aqueduct, is approximately 7,000 GWh per year.

17.4.3. 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.

17.5 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 from existing conditions under the No Project Alternative because Project facilities would not be constructed or operated. Wasteful, inefficient, or unnecessary energy consumption would not occur under the No Project Alternative.

Significance Determination

Construction and operation of the Project would not occur and therefore wasteful, inefficient, or unnecessary consumption of energy resources would not occur. There would be no impacts.

Alternatives 1 and 3 what happened to Alternatives 1a and 1b?

Construction

Petroleum Products

Construction of Alternatives 1 and 3 would require operation of diesel- and gasoline-fueled vehicles and equipment, including employee vehicles and construction equipment. Operation of vehicles and construction equipment would involve consumption of diesel fuel and gasoline. The annual consumption of diesel fuel and gasoline for the approximately 6-year construction period for Alternative 1 or 3 would be highest in 2026. Construction diesel fuel and gasoline consumption are shown in Table 17-13 and Table 17-14, respectively. Construction of Alternatives 1 and 3 would require 4.8% of the amount of diesel fuel consumed annually in the study area and would require 0.4% of the amount of gasoline consumed annually in the study area during 2026 (i.e., year of the highest anticipated consumption of construction fuel).

Construction equipment and vehicles used for construction of Alternative 1 or 3 would meet applicable federal and state standards for operation and fuel efficiency, and energy would be consumed for construction-related activities. The Authority would implement BMPs to reduce construction GHG emissions, which would result in a corresponding decrease in energy consumption during construction. 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. 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 17-9) 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 study area for construction impacts in 2019 was 3,174 GWh, as shown in Table 17-5. Lighting and other electrical equipment 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.

Table 17-13. Diesel Fuel Consumption for Construction of Alternatives 1 and 3 (gallons per year and total gallons)

Gallons of Diesel Fuel	2024	2025	2026	2027	2028	2029	TOTAL	County-wide Consumption	Highest Year Percent Consumption (2026)
Glenn County	192,320	1,010,069	2,099,514	2,399,345	1,227,425	243,595	7,172,267	40,300,000	5.2%
Colusa County	1,009,999	3,018,872	5,953,519	5,266,519	4,887,524	1,468,576	21,605,009	14,800,000	40.2%
Yolo County	8,395	228,253	-	-	-	-	236,649	55,100,000	0.41%
Tehama County	-	-	2,856	16	-	-	2,872	38,100,000	0.01%
Sutter County and Yuba County	1,076	89,389	119,016	115,182	109,064	35,950	469,677	23,300,000	0.51%
Total	**1,211,790**	**4,346,583**	**8,174,906**	**7,781,062**	**6,224,012**	**1,748,120**	**29,486,474**	**171,600,000**	**4.8%**

Table 17-14. Gasoline Fuel Consumption for Construction of Alternatives 1 and 3 (gallons per year and total gallons)

Gallons of Gasoline	2024	2025	2026	2027	2028	2029	TOTAL	County-wide Consumption	Highest Year Percent Consumption (2026)
Glenn County	21,369	112,230	233,279	266,594	136,381	27,066	796,919	18,000,000	1.30%
Colusa County	112,222	335,430	661,502	585,169	543,058	163,175	2,400,557	13,000,000	5.09%
Yolo County	933	25,361	-	-	-	-	26,294	114,000,000	0.02%
Tehama County	-	-	317	2	-	-	319	30,000,000	0.00%
Sutter County and Yuba County	120	9,932	13,224	12,798	12,118	3,994	52,186	70,00,000	0.02%
Total	**134,643**	**482,954**	**908,323**	**864,562**	**691,557**	**194,236**	**3,276,275**	**245,000,000**	**0.37%**

Operations

Petroleum Products

Routine 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 routine inspections and repairs. Over the 2030–2040 modeled operating period, the operation of Alternative 1 or 3 would consume 0.08% of the amount of diesel fuel consumed annually in the study area and would consume 0.03% of the amount of gasoline consumed annually in the study area for operations impacts for petroleum products consumption. Equipment and vehicles used for operation activities for Alternative 1 or 3 would meet applicable federal and state standards for operation and fuel efficiency, and energy would be consumed for operation and maintenance-related activities. 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 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 would implement BMPs 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.

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 conditions. Turbine efficiency would decrease during other operating conditions. Hence, a conservative efficiency of 90% was used to estimate the amount of recovered energy (Sites Project Authority 2020:5-8). 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 have separate pumping and generating units that would provide improved operability, and variable-speed drive would allow pumps to operate more efficiently than constant-speed pumps (Sites Project Authority 2020:2-8).

Alternative 1 or 3 electrical equipment, including pumping and generation equipment, and electrical equipment in buildings and other facilities would be designed and operated to conform to energy efficiency standards. Energy-efficient turbines would be used to generate hydroelectricity and energy-efficient pumps would be used to transport water. The operation of nonresidential structures for Alternatives 1 and 3 would adhere to applicable energy efficiency standards. 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 operations of Alternative 1 or 3 would meet federal and California standards, and gasoline- or diesel-fueled vehicles and equipment would be used only for construction and operation. 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 operation activities would not be used inefficiently, wastefully, or unnecessarily. Construction and operation impacts would be less than significant.

NEPA Conclusion

Construction and operations effects would be the same as described above for CEQA. Alternative 1 or 3 would have no adverse effects on energy resources during construction or operation.

Alternative 2

Construction

Construction of Alternative 2 would consume 5.3% of the amount of diesel fuel consumed annually in the study area (slightly more than Alternatives 1 and 3) and would consume 0.4% of the amount of gasoline consumed annually in the study area (approximately the same as Alternatives 1 and 3) during 2026 (Table 17-15 and Table 17-16). The higher use of diesel fuel associated with construction of Alternatives 1 and 3 is related to construction of several facilities, including three additional saddle dams, that would not be constructed under Alternative 2. Alternative 2 also includes construction that would not be part of Alternatives 1 and 3 (e.g., South Road, longer Dunnigan Pipeline, and Sacramento River discharge). Similar to Alternatives 1 and 3, construction of Alternative 2 would meet applicable federal and state standards for equipment operation and fuel efficiency, and energy would be consumed for construction-related activities. The construction of Alternative 2 would not result in wasteful, inefficient, or unnecessary consumption of petroleum product energy resources.

Electricity would be consumed during construction of Alternative 2, as described under Alternatives 1 and 3. This energy consumption would meet applicable energy efficiency standards. Construction of Alternative 2 would not result in wasteful, inefficient, or unnecessary consumption of electrical energy resources.

Table 17-15. Diesel Fuel Consumption for Construction of Alternative 2 (gallons per year and total gallons)

Gallons of Diesel Fuel	2024	2025	2026	2027	2028	2029	TOTAL	County-wide Consumption	Highest Year Percent Consumption (2026)
Glenn County	173,318	1,059,910	2,274,096	1,870,658	487,711	26,688	5,892,381	40,300,000	5.6%
Colusa County	1,018,115	3,936,757	6,285,584	5,399,954	4,211,474	714,237	21,566,121	14,800,000	42.5%
Yolo County	-	267,739	369,261	-	-	-	637,000	55,100,000	0.7%
Tehama County	-	-	2,856	16	-	-	2,872	38,100,000	0.0%
Sutter County and Yuba County	185	97,286	158,827	115,156	65,554	244	437,252	23,300,000	0.7%
Total	**1,191,619**	**5,361,693**	**9,090,623**	**7,385,783**	**4,764,738**	**741,169**	**28,535,625**	**171,600,000**	**5.3%**

Table 17-16. Gasoline Fuel Consumption for Construction of Alternative 2 (gallons per year and total gallons)

Gallons of Gasoline	2024	2025	2026	2027	2028	2029	TOTAL	County-wide Consumption	Highest Year Percent Consumption (2026)
Glenn County	19,258	117,768	252,677	207,851	54,190	2,965	654,709	18,000,000	1.40%
Colusa County	113,124	437,417	698,398	599,995	467,942	79,360	2,396,236	13,000,000	5.37%
Yolo County	-	29,749	41,029	-	-	-	70,778	114,000,000	0.04%
Tehama County	-	-	317	2	-	-	319	30,000,000	0.00%
Sutter County and Yuba County	21	10,810	17,647	12,795	7,284	27	48,584	70,00,000	0.03%
Total	**132,402**	**595,744**	**1,010,069**	**820,643**	**529,415**	**82,352**	**3,170,625**	**245,000,000**	**0.41%**

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 and fuel efficiency, and energy would be consumed for operation and maintenance-related activities. 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 generation equipment, and electrical equipment in buildings and other 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 used for construction, operations, and maintenance for Alternative 2 would meet federal and California standards, and vehicles and equipment would be used only for construction and operations and maintenance needs and not for other purposes. Diesel fuel use would be slightly more under construction of Alternative 2 when compared to Alternative 1 or 3 due to the construction of the South Road, the longer Dunnigan Pipeline, and the Sacramento River discharge. Energy resources required for Alternative 2 construction and operation activities would not be used inefficiently, wastefully, or unnecessarily. Construction and operation impacts would be less than significant.

NEPA Conclusion

Construction and operations effects would be the same as described above for CEQA. 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 from existing conditions under the No Project Alternative.

Significance Determination

Construction and operation of the Project would not occur and therefore would not conflict or obstruct with a state or local plan for renewable energy or energy efficiency. There would be no impact.

Alternatives 1, 2, and 3

<u>*Construction and Operations*</u>

Federal and state regulations that apply in general to electricity generation and transmission, include: Western Area Power Administration (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 (CAISO) regulations that apply to electricity generation and transmission (Chapter 4, *Regulatory and Environmental Compliance: Project Permits, Approvals, and Consultation Requirements*). The CPUC establishes safety and service standards for public utilities. CAISO conducts grid reliability and transmission planning and implements a generator interconnection process to connect electric power generators to the electric power grid.

<u>California Public Utilities Commission/California Independent System Operator</u>

The electric transmission system in Northern California is owned largely by the federal government (through WAPA) and Pacific Gas and Electric Company (PG&E). Planned transmission system projects are identified during the CPUC and CAISO 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. Electric transmission service would be required to support the PGP electricity requirements and to transmit the hydroelectric energy generated by the PGPs.

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 CAISO 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 PG&E in conjunction with CAISO.

The study, planning, and permitting process conducted by WAPA or PG&E and CAISO 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 CAISO regulations and standards for interconnection to the existing electrical grid. The yet to be completed system impact study for the project vis a vis either the PG&E or WAPA transmission system may have the potential to show additional transmission system investments by the Project proponents to ensure reliable operation of the regional transmission system. If there are any impacts, they probably should not be shown here, but under EN 3.

<u>California Energy Efficiency Standards (CalGreen)</u>

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 2020:1). The Glenn County General Plan (1993) noted that the California Department of Water Resources 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. The POI, transmission, and substation design criteria, depending on the POI option, would incorporate WAPA service and generation, 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

Operation of Alternative 1, 2, or 3 would generate no more than 40 MW of hydroelectric power per facility based on design. 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 and TRR East PGPs for Alternative 1, 2, or 3 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. Additional operations power needs beyond those generated by the Project would be purchased from market sources, with 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 would 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.

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 CAISO and WAPA or PG&E standards for electric transmission and operation of the electrical grid. Construction and operation of Alternative 1, 2, or 3 would result in no impacts.

NEPA Conclusion

Construction and operations effects would be the same as described above for CEQA. Construction of Alternative 1, 2, or 3 would have no adverse effects. Operation of Alternative 1, 2, or 3 would result in generation of renewable hydroelectric power and would result in a beneficial effect on renewable energy production.

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 to energy demand, supply, or capacity would occur under the No Project Alternative. There would be no change in energy consumption or energy generation from existing conditions because the Project would not be constructed and operated.

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. There would be no impacts.

Alternatives 1 and 3 what happened to alternatives 1a and 1b?

Construction

Consumption of gasoline and diesel fuel during construction of Alternatives 1 and 3 would not require a new petroleum product energy supply or distribution infrastructure in the study area. This consumption would not place a substantial burden on regional energy supply because consumption would generally be temporary during construction, would be relatively small when compared to the current available volume, and would be satisfied by the current volume available. Diesel fuel consumption and gasoline consumption for construction of Alternative 1 or 3 for 2026 and the full construction period are presented in Table 17-8a and Impact EN-1. Gasoline consumption for the year of the anticipated highest fuel consumption (2026) would be 0.4% of 2019 annual gasoline sales in the study area for Alternatives 1 and 3. Diesel fuel consumption during the year of the anticipated highest fuel consumption would be 4.8% of 2019 annual diesel-fuel sales in the study area for Alternative 1 or 3.

Operation

Petroleum Products

The negligible volume of petroleum products used for operation 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 17-8b. Gasoline consumption for operations for Alternatives 1 and 3 would be 0.03% of annual gasoline consumption in the study area over the modeled 2030–2040 operation period. Diesel-fuel consumption for operations of Alternatives 1 and 3 would be 0.08% of annual diesel-fuel consumption in the study area over the modeled 2030–2040 operation period. Furthermore, equipment and vehicles used for operations and maintenance of Alternatives 1 and 3 would meet applicable federal and state standards for operation and fuel efficiency.

Electricity

Electricity not generated by Alternative 1 or 3 facilities but required for pumping and other operations would be procured from PG&E or through WAPA. The increased demand caused by pumping would be partially offset by the generating capacity from electricity generation operations. Based on normal load growth and the overall regional and statewide electricity generation and transmission capacity, this approximately 0.05% raise in energy consumption for Alternatives 1 and 3 is a marginal increase in demand and subsequent small reduction in net generation. Impacts are further described below.

When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term reduction in energy generation resulting from Alternatives 1A and 1B (Table 17-10;-276 GWh for Alternative 1A; -260 GWh for Alternative 1B) would constitute 0.14% and 0.13% of total in-state electricity generation, respectively. The reduction in energy generation during Dry and Critically Dry Water Years would be 0.23% for Alternatives 1A and 1B (Table 17-10;-447 GWh for Alternative 1A; -445 GWh for Alternative 1B), respectively. When compared to total electric demand in Northern California (115,940 GWh) (California Energy Commission 2020g:1-2), the long-term net generation would constitute an approximately 0.24% reduction for Alternative 1A and an approximately 0.22% reduction for Alternative 1B; during Dry and Critically Dry Water Years, the net reduction would be approximately 0.39% for Alternative 1A and 0.38% for Alternative 1B.

The modeled net CVP, SWP, and energy generated under Alternative 3 (energy use minus energy production) would be 229 GWh less than the No Action Alternative over the long term and 369 GWh less during Dry and Critically Dry Water Years (Table 17-12). When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term reduction in energy generation resulting from Alternative 3 (Table 17-12; -229 GWh) would constitute 0.12% of total in-state generation. The reduction in energy generation during Dry and Critically Dry Water Years would be 0.19% for Alternative 3 (Table 17-12; -369 GWh). When compared to 2019 total electric demand in Northern California (115,940 GWh) (California Energy Commission 2020g:1-2), the long-term net generation would constitute an approximately 0.12% reduction for Alternative 3 (Table 17-12; -229 GWh). During Dry and Critically Dry

Water Years, the net reduction would be approximately 0.35% for Alternative 3 (Table 17-12; -369 GWh).

Electricity consumption for operation of Alternative 1 or 3 facilities would include electricity consumption for operation of pumps and for administration and maintenance buildings. Alternative 1A electricity consumption would be 92 GWh per year for the long-term average and 40 GWh per year for Dry and Critically Dry Water Years (Table 17-10). Alternative 1B electricity consumption would be slightly more, 96 GWh per year long-term average and 40 GWh per year for Dry and Critically Dry Water Years (Table 17-10). Alternatives 1A and 1B electricity consumption would represent 0.05% of in-state energy generation long-term average and 0.02% of in-state energy generation for Dry and Critically Dry Water Years. Electricity consumption for operation of Alternative 3 facilities would include electricity consumption for operation of pumps and for administration and maintenance buildings. Alternative 3 electricity consumption would be 91 GWh per year for long-term operation and 28 GWh per year for Dry and Critically Dry Water Years (Table 17-12). Alternative 3 electricity consumption would represent 0.05% of statewide demand for long-term operation and 0.01% of statewide demand for Dry and Critically Dry Water Years. Until a system impact study by PG&E or WAPA is undertaken, it is not possible to definitively conclude that there may not be a need for project proponents to invest in additional transmission infrastructure to ensure that the addition of Sites will not negatively impact the reliable operation of the existing regional transmission system.

CEQA Significance Determination and Mitigation Measures

Construction and operation of Alternatives 1 and 3 would not place a substantial demand on regional energy supply, require substantial additional capacity, or substantially increase peak and base period electricity demand. Construction energy consumption would be temporary, would be relatively small when compared to the current available volume, and would be satisfied by the current volume available. Operation energy consumption would be negligible when compared to existing supplies and equipment and vehicles would meet all applicable standards for operation and fuel efficiency. The approximately 0.05% increase in electricity consumption for the operation of Alternative 1 or 3 is a marginal increase in demand and subsequent small reduction in net generation, based on normal load growth and the overall regional and statewide electricity generation and transmission capacity. Construction and operation 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 construction and operation of Alternative 1 or 3 would result in no adverse effect on regional energy resources because the associated energy consumption would represent a marginal increase in demand. The operation of Alternative 1 or 3 would have a beneficial effect on regional energy resources from increased generation of renewable energy.

Alternative 2

Construction

Petroleum Products

Diesel-fuel consumption for construction of Alternative 2 for 2026 and the full construction period are presented in Table 17-8a and described in Impact EN-1. Gasoline consumption would be 0.4% of 2019 annual gasoline sales in the study area for Alternative 2 for the year anticipated to have the highest fuel consumption (2026). Diesel-fuel consumption would be 5.3% of 2019 annual diesel-fuel sales in the study area for Alternative 2 for the highest fuel consumption year. The consumption of petroleum products would be slightly higher than that under Alternatives 1 and 3 due to the construction of additional facilities, as identified in Impact EN-1. Similar to impacts associated with Alternatives 1 and 3, consumption of gasoline and diesel fuel during the construction of Alternative 2 would not require a new petroleum product energy supply or distribution infrastructure in the study area. There would not be a substantial burden on regional energy supply because consumption would generally be temporary during construction, would be relatively small when compared to the current available volume, and would be satisfied by the current volume available.

Operation

Petroleum Products

Gasoline and diesel fuel consumption for operation of Alternative 2 is shown in Table 17-8b. Diesel fuel consumption for Alternative 2 operations would be almost the same as that for Alternatives 1 and 3 (0.07%) of annual diesel-fuel consumption in the study area for the 2030–2040 operation period. Gasoline consumption for Alternative 2 operations would be the same as that for Alternatives 1 and 3 (0.03%) of annual gasoline consumption in the study area for the modeled 2030–2040 operation 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 not generated by Alternative 2 facilities but required for pumping operations would be procured from PG&E or through WAPA. The increased demand caused by Alternative 2 pumping would be partially offset by the electricity generating capacity from Alternative 2 operations. Based on normal load growth and the overall regional and statewide electricity generation and transmission capacity, this approximately 0.04% increase is a marginal increase in demand and subsequent reduction in net generation (slightly less than Alternative 1 or 3). Net generation for Alternative 1 and Alternative 3 would be lower than that of Alternative 2 for long-term averages, and net generation for Alternative 1 and Alternative 2 would be approximately the same for Dry and Critically Dry Water Years (Table 17-10, Table 17-11, and Table 17-12). Net generation for Alternative 3 for Dry and Critically Dry Water Years would be higher than for Alternative 1 or Alternative 2 (Table 17-10, Table 17-11, and Table 17-12).

The modeled CVP, SWP, and Project energy generated under Alternative 2 (energy use minus energy production) would be 248 GWh less than the No Action Alternative over the long term and 431 GWh less during Dry and Critically Dry Water Years (Table 17-11). When compared to the total in-state energy generation identified in Table 17-2 (194,842 GWh), the long-term reduction in energy generation resulting from Alternative 2 would constitute 0.13% of total in-state generation. The reduction in energy generation during Dry and Critically Dry Water Years would be 0.22% for Alternative 2. These reductions in energy generation compared to total in-state generation are very similar to the results for Alternatives 1 and 3 previously presented (i.e., very low). When compared to 2019 total electric demand in Northern California (115,940 GWh) (California Energy Commission 2020g:1-2), the long-term net generation would constitute an approximately 0.21% reduction for Alternative 2. During Dry and Critically Dry Water Years, the net reduction would be approximately 0.37% for Alternative 2. These reductions in energy generation compared to total electrical demand are also very similar to the results for Alternatives 1 and 3 presented above.

Alternative 2 electricity consumption would be 85 GWh per year for long-term operation and 38 GWh per year for Dry and Critically Dry Water Years (Table 17-11). Alternative 2 electricity consumption would represent 0.04% of in-state electricity generation for long-term operation and 0.02% of in-state electricity generation for Dry and Critically Dry Water Years. Until a system impact study by PG&E or WAPA is undertaken, it is not possible to definitively conclude that there may not be a need for project proponents to invest in additional transmission infrastructure to ensure that the addition of Sites will not negatively impact the reliable operation of the existing regional transmission system.

CEQA Significance Determination and Mitigation Measures

Construction of Alternative 2 would result in energy impacts similar to those for Alternatives 1 and 3, but the energy consumption would be slightly higher. The energy consumption for operation of Alternative 2 would be negligible, which would be the same as for Alternatives 1 and 3. The approximately 0.04% increase in electricity consumption is a marginal increase in demand and subsequent reduction in net generation (slightly less than Alternative 1 or 3), based on normal load growth and the overall regional and statewide electricity generation and transmission capacity. Construction and operation impacts would be less than significant.

NEPA Conclusion

Construction impacts and operation effects for Alternative 2 would be the same as those described above for CEQA. The construction and operation of Alternative 2 would result in no adverse effect on regional energy resources because the associated energy consumption would represent a marginal increase in demand. The operation of Alternative 2 would have a beneficial effect on regional energy resources from increased generation of renewable energy.

17.6 References

17.6.1. Printed References

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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.

Comments on Power Modeling Documentation

1. Page 2: Under Energy Generation Calculations: WAPA is listed as Western Area Power **Authority.** Authority should be changed to **Administration.**

2. Page 19: Noticed that analysis included:

    a. • No Action Alternative 011221
    b. • Alternative 1A 011221
    c. • Alternative 1B 011221
    d. • Alternative 2 011221
    e. • Alternative 3 020121

    Chapter 2 (Alternatives Section) mentioned the No Action Alternative, along with Alternative 1 (1.5 MAF and up to 7% USBR financing), Alternative 2 (1.43 MAF and no USBR financing), and Alternative 3 (1.5 MAF and up to 25% USBR financing). May be helpful to get clarification as the difference between Alternative 1A and 1B and to see if Alternatives 2 and 3 still remain the same.

3. Page 109 and starting with Figure 5-1a: Potential disconnect between the way the report calculates monthly net power revenues for the CVP power system. It is true when CVP power customers "buy" from the CAISO and when WAPA injects Base Resource power into the CAISO they do so at hourly locational marginal prices calculated by the CAISO. From a repayment standpoint, customers are still "on the hook" for the actual cost of the Base Resource. This calculation is based on a projected cost incurred approach which allocates forecasted costs assigned on the basis of Base Resource allocated percentage over a modified 12-month repayment period. Thus WAPA gets its actual estimated cost rates independent of whether the CAISO market price is either higher or lower than that. When DWR used forecasted 2030 prices, was the data from commercially available or internal sources and what was the estimated MW-hour price? Was this an average price over the year, or did they use seasonal and/or monthly average prices when calculating the anticipated net revenues? Using Table 17A, I've calculated a rough cost of about $54.19/MW-Hr. Suggest you check with someone in the merchant section to determine if that value is appropriate (Robert DeLizio or Charles Faust). Since WAPA markets on a net generation basis, gross generation numbers for CVP project-use is not tied to market rates, but actual cost of service estimates.

4. Page 110, Tables 5: See that with the only exception of alternative 2, the studies show net revenue increases for the CVP power function. Could you generally explain how CVP power revenues will be increasing slightly for Alternatives 1a, 1b, and 2, when adding on Sites is expected to increase project use energy requirements? The report says that the downstream alternatives reflect operations downstream with the presumed operational flexibility of Sites. Could

you identify the major changes in water/power operations which would explain these increases?

5. Starting on page 43, Table 2-1a through Table 2-4b and on page 65 Table 3-1a through Table 3-4b: Total gross generation and project use requirements appear not to vary significantly among the five alternatives. On page 307, Table 14-1a through Table 14-4b show monthly simulated data which shows a wide variety in project use energy requirements for a standalone Sites Unit. Using simulated data, each alternative would generate on a standalone basis, a need for additional 37 to 48 gigawatt hours over the no project base case. The report indicates that the water and power modeling were done in simulate overall operating conditions in future years for each alternative. Can the Sites Authority summarize the major water/power operational benefits produced by the standalone unit which would generate the savings for the CVP water and power system resulting in a 3 or 4 gigawatt-hour increase on the CVP power system?

6. Page 263, Table 12-1a: Compared these monthly tables (full simulation period) and compared them with summary table 26 and found that with the exception of Alternative 2, the total generation values were within 1 rounding point. Noticed a 3 point variation for alternative 2 (e.g., Table 12 shows 37 gigawatt-hours, while table 26 shows 34). Don't know if this is due to rounding or a transposing of data. May want to check.

7. Page 307, Table 14-1a: Under the No Action Alternative with no Sites Facilities, an estimated 14-gigawatt hours of energy is consumed under net generation category. Is this because in the absence of the project, users in the Tehama Colusa Service area are going to be independently receiving additional water supplies over their current levels, and thus increasing project-use energy consumption levels?

8. Pag 329 Table 15: Similar to seeing negative values for net generation, see negative values for net generation revenues under the No Action Alternative. Is that because like above, in the absence of the project, users in the Tehama-Colusa Canal Service area are going to be receiving additional water supplies over their current levels, thus increasing project-use energy levels?

9. Page 374, Table 17: Revenues for CVP, SWP, and Sites appear aggregated, giving the appearance of financial integration. I believe Sites (NODOS) was authorized as an operational integration with CVP and SWP, but I'm not so sure that such authorization was given for financial integration. What is the purpose of aggregating financial revenues for all three projects?

10. I understand that the power impact study still remains to be undertaken once a more definitive idea of the preferred alternative or alternatives are identified. May need to keep a place holder to include the results of this study, especially if system reinforcements are needed for either the CVP or the PG&E system in

order to determine   This Appendix is probably not the best place for it, but it still needs to be included elsewhere in the report, especially if the system impact study shows an impact on existing transmission users (PG&E or WAPA), as mitigation impacts are going to add to the project's overall cost.

Comments on Table 17A Power and Pumping Cost Reporting Metrics

1. When looking at net generation values for this table, the summary net gain/loss for each alternative over the No Action Alternative appear to vary from the aggregated net revenues (for simulated run) for the CVP shown in Tables 5 on page 110.

2. Noticed that Table 17a for Sites Gross generation for the most part tied in with Table 12 of the Power Modeling Methodology Report. Noticed a variance of 37 gw-hrs for Table 12 versus 34 gigawatt hours for Tables 17a and Table 26 of the report.

Comments on Chapter 17 Write Up for Energy Resources

1. Page 17-2, Table 17-1b. Summary of Operations Impacts and Mitigation Measures for Energy Resources: Without a definitive system impact study completed for either the PG&E or WAPA transmission system (pending definitive identification of the alternatives). It could be potentially premature to conclude that there are either no negative impacts or potential benefits, especially if the system impact study concludes that system reinforcements are required to ensure the continued reliable operation of the regional transmission system. Would recommend keeping this as a placeholder, and update as needed upon completion of the system impact study for either the PG&E or WAPA transmission system.

2. Page 17-3, 17.2.1.1 Electricity Generation: An observation is made about nuclear energy's portion of the California energy portfolio. Note that Diablo Canyon, California's lone currently operating power plant is scheduled to be shuttered by PG&E on or about 2024. Since the project is slated to become

operational in 2030, did the report evaluate the impact if any, of the Diablo Canyon being shuttered?

3. Page 17-22, Impact analysis for Alternatives 1 and 3: What happened to Alternatives 1a and 1b?

4. Page 17-29, Alternatives 1, 2, and 3: What happened to Alternatives 1a and 1b?

5. Page 17-29; California Public Utilities Commission/California Independent System Operator: It is true that either WAPA or PG&E through their respective transmission planning processes will ensure an efficient/effective interconnection. However, until such a study is conducted it may not be possible to definitively conclude that addition of the Sites Project may result in the need for additional transmission infrastructure investments on the part of the project proponents to ensure the reliable operation of the regional transmission system. If there is an impact, probably should be shown under EN-3.

6. Page 17-23, 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: For Alternatives 1 and 3, as well as Alternative 2, until a system impact study is undertaken and completed by WAPA or PG&E, it is not possible to definitively conclude that additional transmission infrastructure is not needed by the project proponents of Sites to include it in the regional transmission system.

   The existing LT Gen runs are based on monthly energy forecasts. In actuality, the power markets are run on an hourly and in real-time and near real-time increments. Although the long-term simulations show that for all alternatives, the yearly simulated values show very little impact. However, some months the energy consumption requirements for the Sites addition is not insignificant. During those months when existing preference power customers might not have access to the same "net generation" as when compared against the no action alternative, if in the event they are required to purchase those "shortfalls", and if those shortfalls are priced at rates which would have exceeded their Base Resource allocations, shouldn't those "purchases" be identified and evaluated as to their potential impacts?

7. Page 17-34; Electricity: A point is made that energy requirements to support pumping plant activity at Sites would be purchased from PG&E or WAPA. Recommend considering using the word through WAPA instead from WAPA. From WAPA implies Sites would be receiving a power allocation. That may not necessarily be the case. In the event Sites asks WAPA to be its scheduling coordinator, WAPA would more than likely purchase power in the electricity

markets on Site's behalf and not necessarily assign a new allocation of power from the CVP, The same observation applies to other such descriptions for electricity for Alternatives 1a, 1b, the 3 if such wording similarly exists.

8.