Chapter 21
Energy

21.1 Environmental Setting/Affected Environment

The section describes potential effects to these energy resources from construction and operation of the action alternatives in the study area (the area in which impacts may occur). The study area consists of the Plan Area (the area covered by the BDCP), which is largely formed by the statutory borders of the Delta, along with areas in Suisun Marsh and the Yolo Bypass; and the Areas of Additional Analysis (see Chapter 3, *Description of Alternatives*, Section 3.3.1). New water conveyance facilities associated with BDCP would be constructed, owned, and operated as a component of the State Water Project (SWP). While additional power used to move water through the new BDCP facilities would be procured by DWR, the pumping requirements are directly linked to the SWP and Central Valley Project (CVP) exports and the monthly water supply deliveries to the various SWP and CVP contractors. Accordingly, this section discussed the energy generation at the SWP and CVP hydropower facilities and the energy use for pumping water supplies into the various canals and tunnels in the water conveyance and distribution systems.

This chapter evaluates the energy demand for each BDCP alternative relative to Existing Conditions (for CEQA) and No Action Alternative (for NEPA). Existing Conditions (also referred to as *CEQA Baseline*) is defined as installed SWP and CVP capacity in 2010. The No Action Alternative (also referred to as the *NEPA point of comparison*) is defined as future SWP and CVP capacity in 2060 independent of BDCP actions. The difference in energy demand between each BDCP alternative and the No Action Alternative represents the net impact of the project under 2060 conditions. The difference in energy demand between each BDCP alternative and the CEQA baseline represents net impact of the project, relative to Existing Conditions (2010).

Historic CVP and SWP energy generation and use provide the energy context for evaluating the additional energy requirements for the BDCP alternatives. Energy effects are evaluated as the additional pumping energy requirements for the BDCP alternatives and the additional energy for pumping increased Delta exports for some of the BDCP alternatives. The BDCP alternatives may cause upstream reservoir operations changes that could alter the hydropower generation in some months or alter the pumping at existing facilities in other months. These changes could increase the net energy gap between the CVP and SWP hydropower generation and the pumping energy uses.

Hydropower energy generation is a major project purpose for the CVP and SWP. Hydropower energy has always been an important part of the benefits and financing of state, federal, and private water resources developments in California. The runoff from the Sierra Nevada and Cascade mountains provided a great potential for hydropower development, which has now been harnessed to pump water supplies into the CVP and SWP canals, San Luis Reservoir, and water distribution systems. Some additional energy is used for groundwater pumping for CVP and SWP contractors when surface water supplies are limited in dry years.

Additional pumping and Delta export energy requirements for the BDCP alternatives is simulated using the CALSIM model (version II). It is important to note that given the inherent complexity of the SWP, CVP, and Delta operation, planning tools such as CALSIM-II may not produce the same operational patterns, energy demand and generation profiles that have been observed in recent years. The ever changing regulatory environment that the SWP and CVP projects operate under is a challenge for planning tools, such as CALSIM-II. Energy calculations based on CALSIM-II represent a reasonable, though overstated, scenario based on historic monthly flows and reservoir storage. Additional details on CALSIM-II are provided in Section 21.1.3.1, *CVP and SWP Energy Generation*.

Understanding the energy evaluation will be easier with a brief introduction to some basic energy units. The basic units of electrical power (capacity) are kilowatt (kW), megawatt (MW), and gigawatt (GW). A megawatt is 1,000 kW, and a gigawatt is 1,000,000 kW or 1,000 MW. It is common for energy to be reported as the power supplied or consumed over a unit of time. For instance, generating electricity at the rate of 1 kW for 1 hour is a kilowatt hour (kWh). A 100 MW (100,000 kW) generating facility would produce 2,400,000 kWh (2,400 megawatt hours (MWh) or 2.4 gigawatt hours [GWh]) in a day.

21.1.1 CVP Hydropower Generation and Pumping Facilities

The Bureau of Reclamation (Reclamation) planned, constructed, financed, and operates the CVP energy-producing facilities. Western is within the Department of Energy (DOE) and is responsible for providing transmission/distribution services and marketing excess energy produced by CVP facilities. Western is one of four national power marketing administrations that sells and transmits power generated by federal hydroelectric facilities (Western Area Power Administration 2009).

The amount of water released from CVP reservoirs controls the CVP energy generation each year. The CVP energy use for pumping water south of the Delta depends on the CVP pumping from the Delta and seasonal storage in San Luis Reservoir. On an annual basis CVP hydropower plants have historically generated energy in excess of the amount needed to pump CVP water, thus allowing Western to sell this excess energy to other electric utilities, municipalities, industrial customers, and other identified Preference Power Customers. Preference Power Customers are publicly owned systems and/or nonprofit cooperatives that are given preference by law over investor-owned utilities to receive power generated by federal projects (Bureau of Reclamation 2009). Western primarily markets power using long-term firm power contracts. When CVP generation is not sufficient to cover CVP pumping requirements on a daily basis, Western purchases needed electricity from other sources.

CVP hydropower and pumping facilities are discussed in the following sections. Table 21-1 shows energy generation and flow parameters; Table 21-2 shows pumping capacities and energy requirements of these facilities. Energy generation at the reservoir power plants and pumping energy at the Gianelli pumping plant depend on the reservoir storages (i.e., elevations) that controls the water heads (feet).

Table 21-1. CVP Hydropower Generation Capacity of Facilities

Facility	Water Head (feet) Min	Water Head (feet) Max	Max Flow (cfs)	Max Volume (af/day)	Capacity (MW)	Max Generation (MWh)	Generator Efficiency	Energy Factor (kWh/af)
Trinity Dam and Powerplant	245	470	4,200	8,400	140	3,360	0.85	400
J. F. Carr Powerplant	692	712	3,300	6,600	160	3,840	0.82	582
Spring Creek Powerplant	602	636	4,200	8,400	190	4,560	0.85	543
Shasta Dam and Powerplant	260	487	18,000	36,000	710	17,040	0.97	473
Keswick Dam and Powerplant	74	87	15,000	30,000	105	2,520	0.97	84
Folsom Dam and Powerplant	197	336	8,000	16,000	210	5,040	0.94	315
Nimbus Dam and Powerplant	38	45	4,500	9,000	15	360	0.89	40
New Melones Dam and Powerplant	200	480	10,000	20,000	380	9,120	0.95	456
Gianelli Pumping-Generating Plant	100	320	16,000	32,000	400	9,600	0.94	300
O'Neill Dam and Pumping-Generating Plant	45	53	6,000	12,000	25	600	0.94	50

af=acre-feet
cfs=cubic feet per second

Table 21-2. CVP Pumping Capacity of Facilities

Pumping Plant	Pumping Head (feet) Min	Pumping Head (feet) Max	Max Flow (cfs)	Max Volume (af/day)	Capacity (hp)	Capacity (MVA)	Efficiency	Energy Factor (kWh/af)
Red Bluff (under Construction)		25	2,500	5,000	8,000	6	0.87	29
C. W. "Bill" Jones		197	5,000	10,000	140,000	105	0.78	252
O'Neill Pumping-Generating Plant	45	53	4,200	8,400	36,000	27	0.69	77
Gianelli Pumping-Generating Plant	100	320	11,000	22,000	504,000	378	0.78	412

af=acre-feet
cfs=cubic feet per second
hp=horsepower
MVA=megavolt ampere

21.1.1.1 Trinity River and Sacramento River Facilities

The Trinity River Division includes the Trinity Dam and Powerplant, the Lewiston Dam and Powerplant, the Judge Francis Carr Powerplant, and the Spring Creek Powerplant. The Trinity Dam and Powerplant were completed in 1962 with a maximum water storage capacity of 2,450 thousand acre-feet (TAF) (Bureau of Reclamation 2012). Trinity Powerplant has a capacity of 140 MW with a maximum water head of 470 feet at full storage of 2,450 TAF. The minimum head is about 245 feet at the minimum storage for power generation of about 325 TAF. The maximum flow through the penstocks is about 4,200 cubic feet per second (cfs) at full storage. With an assumed turbine/generator efficiency of 85%, the energy generation factor (kilowatt hours per acre-foot [kWh/af]) is 400 kWh/af at maximum storage and is about 200 kWh/af at minimum storage. (The energy generation factor is approximately the water head multiplied by the turbine/generator efficiency.)

Lewiston Dam and Powerplant are 7 miles downstream of Trinity Dam. Lewiston Powerplant began operation in 1964 and has one generating unit with a capacity of 500 kW (Bureau of Reclamation 2012). Lewiston Powerplant generates electricity for the plant itself and the local fish hatchery, but does not generate much additional CVP power.

J. F. Carr Powerplant receives water from Lewiston Lake through the Clear Creek Tunnel and is located at the upstream end of Whiskeytown Lake. Operation began in 1963, and the two generating units were upgraded in 1984 to the current capacity of about 160 MW (Bureau of Reclamation 2012). The Carr Powerplant was designed to allow full diversions from the Trinity River. The Trinity Restoration Program in 2002 increased the Trinity River flows and reduced the average diversion from 1,000 TAF per year (TAF/yr) to about 500 TAF/yr. This reduced the average flow through the Carr Powerplant and the Spring Creek Powerplant by about 500 TAF/yr. The maximum water head is about 712 feet, with a maximum turbine flow of 3,300 cfs. The energy generation factor is about 582 kWh/af with an efficiency of 82%.

Spring Creek Powerplant, built in 1964, receives water from Whiskeytown Lake through the Spring Creek Tunnel and discharges water to Keswick Reservoir. The current capacity is 190 MW (Bureau of Reclamation 2012). The maximum water head is about 636 feet, with a maximum turbine flow of 4,200 cfs. The energy generation factor is about 543 kWh/af with an efficiency of 85%.

The Shasta Division consists of Shasta Dam and Powerplant and Keswick Dam and Powerplant. Construction of these CVP facilities began in 1938 and was completed in 1945. Shasta Powerplant has five generating units (and two station units). The Shasta Temperature Curtain was constructed (completed in 1997) to allow low-level releases for temperature control to be made without bypassing the power outlets. This allows energy generation year-round while still providing the coolest possible water temperatures below Keswick Dam. The current capacity of Shasta is 710 MW (Bureau of Reclamation 2012). The maximum water head is about 487 feet at maximum storage and is about 260 feet at minimum storage. The maximum flow rate is 18,000 cfs with an energy factor of about 473 kWh/af and an efficiency of about 97%.

Keswick Dam and Powerplant are located downstream of the Shasta Dam on the Sacramento River. The dam regulates peaking power releases from Shasta Dam to provide a constant release from Keswick Dam to the Sacramento River. Keswick Powerplant has three generating units with a combined capacity of 105 MW (Bureau of Reclamation 2012). The water head varies from about 74 feet to 87 feet (less head at high discharge). The maximum turbine flow is about 15,000 cfs with an energy factor of about 84 kWh/af and an efficiency of about 97%.

The Sacramento River Division includes the Red Bluff Diversion Dam, Corning Pumping Plant, and Corning and Tehama-Colusa Canals, but no facilities for the generation of electricity. The Corning Pumping Plant uses electricity and the new Red Bluff Pumping Plant (under construction) that will divert water into the Tehama-Colusa Canal (without lowering the Red Bluff diversion Dam gates) will use energy in the near future. The Corning Pumping Plant has six pumping units with a combined capacity of about 32 MW. The pumping head is about 70 feet and the flow is about 425 cfs with an efficiency of 85% and a pumping energy factor of about 85 kWh/af.

21.1.1.2 American River Facilities

The American River Division includes Folsom Dam and Powerplant, Nimbus Dam and Powerplant, Folsom Pumping Plant, and the Folsom South Canal. The Folsom Powerplant consists of three generating units with an installed capacity of 210 MW (Bureau of Reclamation 2012). The maximum water head at the Folsom Powerplant is about 336 feet at maximum storage with a maximum flow of 8,000 cfs with an energy factor of 315 kWh/af and an efficiency of 94%. The Folsom Pumping Plant supplies local domestic water supplies. The Nimbus Powerplant has two generating units with a capacity of about 15 MW. The maximum water head is 45 feet and the maximum flow is 4,500 cfs with an energy factor of about 40 kWh/af and an efficiency of 89%.

21.1.1.3 Stanislaus River Facilities

The New Melones Dam and Powerplant are on the Stanislaus River. New Melones Reservoir has a water storage capacity of 2.4 million acre-feet at a maximum pool elevation of 1,088 feet. The New Melones Powerplant has two generators with a capacity of 380 MW. The maximum water head is about 480 feet and the maximum turbine flow is about 10,000 cfs with an energy factor of about 456 kWh/af and an efficiency of 95%.

21.1.1.4 CVP Delta-Mendota Canal Facilities

The C. W. “Bill” Jones Pumping Plant is north of the city of Tracy and consists of six pumps. The pumps are each rated at 22,500 horsepower (hp) (16.7 MW), for a maximum energy requirement (capacity) of about 100 MW. The pumping plant has a maximum water head of about 197 feet and a maximum flow of about 5,000 cfs. The pumping efficiency is about 78% and the pumping energy factor is about 252 kWh/af. (Bureau of Reclamation 2012). Water from the Jones pumping plant flows into the Delta-Mendota Canal. The Contra Costa Water District (CCWD) diverts CVP water from the Delta for municipal and industrial and irrigation purposes. The Rock Slough Pumping Plant and the Contra Costa Canal were built as part of the CVP, but the pumping plant is now operated by CCWD.

The California Aqueduct/ Delta-Mendota Canal Intertie (Intertie) is currently being constructed to pump water from the Delta-Mendota Canal to the California Aqueduct (Bureau of Reclamation 2012). The Intertie Pumping Plant with a capacity of about 400 cfs will allow the Jones Pumping Plant to operate at full authorized pumping capacity of 5,000 cfs year-round. The lower Delta-Mendota Canal capacity of 4,200 cfs limits the Jones pumping in the winter when no water deliveries are being made. The pumping head will be about 50 feet and the energy requirement will be 2 MW (Bureau of Reclamation 2012). The Intertie will be completed in 2012. The O’Neill Dam and Pumping-Generating Plant are at the convergence of the O’Neill Forebay and the Delta-Mendota Canal. The dam was completed in 1967. The O’Neill Pumping-Generating Plant utilizes six pumping units to lift water about 53 feet (depending on the surface height of the water) from the Delta-

Mendota Canal to the O'Neill Forebay. The pumping units have a maximum flow of 4,200 cfs and require about 2.4 MW of energy capacity. When water is released to the Delta-Mendota Canal, the six units have a maximum flow of about 1,000 cfs and generate 25 MW (Bureau of Reclamation 2012).

The Gianelli Pumping-Generating Plant was constructed as a joint CVP-SWP facility between O'Neill Forebay and San Luis Reservoir. The pumping head ranges from a minimum of 100 feet at minimum storage in San Luis Reservoir to about 320 feet at maximum storage. The plant has eight pumping-generating units that can pump a maximum of 11,000 cfs with a pumping energy factor of 412 kWh/af, with an efficiency of about 78% and an energy requirement of 380 MW. When releasing a maximum flow of 16,000 cfs from San Luis Reservoir to O'Neill Forebay, the 8 units generate a maximum of 400 MW with an energy factor of about 300 kWh/af and an efficiency of about 95%. Because the Gianelli Pumping–Generating Plant is a joint SWP and CVP facility, the water pumped or released by each agency determines the energy supplied or energy generated by each agency (Bureau of Reclamation 2012).

21.1.2 SWP Hydropower Generation and Pumping Facilities

The SWP is one of the largest water and power systems in the world. Hydroelectric and natural gas facilities, along with contractual arrangements, are the major power sources of SWP power operations. The multipurpose nature of the SWP affects how its facilities are operated. Most times, the top operational priority is to maximize water deliveries to State Water Contractors, within the scope of regulatory requirements. The SWP was designed and built with other important purposes in mind, including flood control, hydroelectric power generation, protection of fish and wildlife and recreation. The basic operational tools used by DWR to accomplish SWP goals have been to increase or decrease upstream water releases, change Delta pumping rates and store water conveyed through the Delta at San Luis Reservoir. For a more detailed discussion of SWP operations, refer to Section 5.1.2, *SWP and CVP Facilities and Operations* in Chapter 5, *Water Supply*.

SWP operations, especially Delta export pumping, are closely coordinated with those of the larger federal CVP (see Section 21.1.1). The pumping plants of both systems are located in the same area of the South Delta. Their aqueduct operations are also coordinated, as are storage and pumping at San Luis Reservoir, a key facility serving both systems. For more detail on the coordinated operations of CVP and SWP, see Section 5.1.2.3, *SWP/CVP Coordinated Facilities and Operations in Chapter 5, Water Supply*.

Table 21-3 and Table 21-4 provide a snapshot into the SWP 2001–2010 pumping and generating operations.

Table 21-3. SWP Pump Load, SWP Hydro Generation (including Castaic), and SWP Water Deliveries

Parameter	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total Pump Load (GWh)	6,568	8,276	8,912	9,801	8,289	9,114	9,291	5,707	5,444	7,225
Total Generation (GWh)	3,167	4,090	4,599	5,282	4,083	5,978	4,913	2,813	3,031	3,480
Water (Acre-feet)	1,534,263	2,564,857	2,890,215	2,594,999	2,826,210	2,971,851	2,081,217	1,234,240	1,232,753	1,930,929
Total Water Deliveries (Acre-feet)	3,193,771	4,009,873	4,168,151	4,328,460	4,726,363	4,827,082	4,061,696	2,838,128	2,915,435	3,502,986

Table 21-4. Hyatt-Thermalito Generation (Monthly)

YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total for Year
2001	97.98	57.22	79.77	78.29	192.98	162.10	149.27	139.14	55.69	89.33	63.77	69.15	1,235
2002	54.06	27.76	43.08	78.70	155.01	218.52	307.66	222.95	121.50	102.66	71.77	81.97	1,486
2003	58.89	161.48	49.90	44.26	153.03	226.40	483.35	317.10	171.80	114.59	140.79	111.89	2,033
2004	95.32	155.12	235.37	257.63	172.53	261.17	374.85	296.46	124.04	111.09	108.60	101.40	2,294
2005	67.25	37.04	54.21	39.80	152.66	224.19	258.22	253.03	192.07	158.69	155.75	240.64	1,834
2006	401.36	263.32	480.71	518.53	435.88	265.87	259.89	266.94	193.04	139.52	163.05	122.69	3,511
2007	111.78	102.26	139.29	162.56	172.93	253.08	336.03	270.96	176.16	122.62	144.29	84.89	2,077
2008	43.96	39.18	27.43	117.73	126.14	174.43	142.01	121.72	57.62	46.72	48.32	56.00	1,001
2009	38.60	18.38	12.18	143.24	153.24	201.49	348.92	155.96	73.74	90.01	120.60	93.61	1,450
2010	46.14	30.12	41.37	14.71	99.70	122.41	307.05	309.12	238.19	114.37	125.46	74.96	1,524

From a power resourcing perspective, SWP has a diversified portfolio of resources to meet its annual pumping requirements. In Figure 21-1, the distribution of resources used to meet the load requirements in 2010 is shown. Nearly sixty-percent of the 2010 load was met with hydro resources including SWP system resources (Hyatt-Thermalito, Gianelli, and Warne, and Devil Canyon), long-term contract hydropower at Pine Flat and Castaic reservoirs, small hydro resources (Alamo, Mojave Siphon, and contract small hydro) as well as coal power from the RG4 facility, and the balance of SWP pumping needs met with short- and mid-term contract power purchases and daily and real-time purchases from the California Independent System Operator's (CAISO) energy market.

As DWR resources for future SWP delivery requirements, it will pursue cleaner resources to reduce SWP greenhouse gas emissions as outlined in DWR's Climate Action Plan-Phase I: Greenhouse Gas Emissions Reduction Plan (see Chapter 22, *Air Quality and Greenhouse Gas Emissions*, Section 22.3.2.3, for additional details on the CAP). The 2020 portfolio (Figure 21-2) will be comprised of a portion of the Lodi Energy Center combined cycle power plant, and new renewable energy resources.

SWP hydropower and pumping facilities are discussed in the following sections. Refer to Table 21-3 for energy generation and flow parameters and Table 21-4 for pumping capacities and energy requirements during the discussion of these facilities. Energy generation at the Hyatt powerplant and energy required at the Gianelli pumping plant depend on the reservoir storages (i.e., elevations) that controls the water heads (feet). Refer to Table 21-5 for energy generation and flow parameters and Table 21-6 for pumping capacities and energy requirements during the discussion of these facilities. Energy generation at the Hyatt powerplant and energy required at the Gianelli pumping plant depends on the reservoir storages (i.e., elevations) that controls the water heads (feet).

Table 21-5. SWP Hydropower Generation Capacity of Facilities

	Water Head (feet)						
Facility	Min	Max	Max Flow (cfs)	Max Volume (af/day)	Capacity (MW)	Generator Efficiency	Energy Factor (kWh/af)
Edward Hyatt Powerplant (Oroville)	410	676	16,950	33,620	819	0.86	585
Thermalito Pumping-Generating Plant	85	102	17,400	34,513	120	0.82	83
Thermalito-Low Flow	63	77	615	1,220	3	0.84	65
Warne	719	739	1,565	3,104	74	0.77	572
Alamo	115	141	1,740	3,451	17	0.84	118
Mojave	81	136	2,880	5,712	32	1.00	136
Devil Canyon		1,406	2,940	5,831	280	0.82	1,152

Table 21-6. SWP Pumping Capacity of Facilities

	Pumping Head (feet)							
Pumping Plant	Min	Max	Max Flow (cfs)	Max Volume (af/day)	Capacity (hp)	Capacity (MVA)	Efficiency	Energy Factor (kWh/af)
Hyatt Powerplant (Oroville)	500	660	5,610	11,127	519,000	387	0.79	835
Thermalito Pumping-Generating Plant	85	100	9,120	18,090	120,000	89	0.84	119
Harvey O. Banks	236	252	10,670	21,164	330,000	246	0.90	279
South Bay		566	330	655	27,750	21	0.75	759
Del Valle		38	120	238	1,000	1	0.51	75
Dos Amigos	107	125	15,450	30,645	240,000	179	0.89	140
Las Perillas		55	461	914	4,050	3	0.69	79
Badger Hill		151	500	992	11,750	9	0.71	212
Devil's Den		521	134	266	10,500	8	0.74	707
Bluestone		484	134	266	10,500	8	0.68	707
Polonio Pass		533	134	266	10,500	8	0.75	707
Buena Vista		205	5,405	10,721	144,500	108	0.85	241
John R. Teerink		233	5,445	10,800	150,000	112	0.94	249
Ira J. Chrisman Wind Gap		518	4,995	9,908	330,000	246	0.87	596
A. D. Edmonston		1,926	4,480	8,886	1,120,000	835	0.85	2,256
Oso		231	3,252	6,450	93,800	70	0.89	260
Pearblossom		540	2,575	5,108	203,200	152	0.76	712
af=acre-feet								

MVA= megavolt ampere

21.1.2.1 Feather River Facilities

The Oroville-Thermalito Complex includes Edward Hyatt Powerplant, Thermalito Diversion Dam and Powerplant, and the Thermalito Pumping-Generating Plant. Construction began in 1957 and the Oroville and Thermalito facilities became operational in 1968 (California Department of Water Resources 2009a, 2009b). Oroville Dam is the tallest dam in the United States, with a structural height of 770 feet with a crest elevation of 922 feet. Lake Oroville has a maximum storage capacity of 3,537 TAF with a maximum water elevation of 900 feet (California Department of Water Resources 2009a, 2009b). Table 21-6 gives the energy generation and flow parameters and the pumping capacities and energy requirements for each of the SWP facilities.

The Edward Hyatt Powerplant is an underground pumping-generating facility at the base of Oroville Dam that generates power from water released from the dam and can pump water from Thermalito Forebay for pumped-storage operations (not used very often). The water head ranges from about 410 feet at minimum operating storage to about 676 feet at maximum storage. The maximum generation capacity for the Hyatt Powerplant is 819 MW with a maximum flow of about 16,950 cfs. The energy factor is about 585 kWh/af at maximum head and is about 350 kWh/af at minimum head, with an efficiency of about 86%. When pumping water from Thermalito Forebay, the pumping units have a capacity of about 5,610 cfs with a pumping energy factor of 835 kWh/af and a pumping efficiency of about 79%. The maximum energy requirement for this pumping is about 387 MW (California Department of Water Resources 2009b).

Thermalito Diversion Dam and Powerplant are approximately 4.5 miles downstream from Oroville Dam on the Feather River. The dam diverts water to the Thermalito Forebay Canal for use at the Thermalito Pumping-Generating Plant. The small Thermalito Diversion Dam Powerplant has one generating unit with a maximum flow of 615 cfs and a water head of 63–77 feet, generating a maximum of about 3 MW with an energy factor of about 65 kWh/af and an efficiency of about 85%.

The Thermalito Pumping-Generating Plant is about 4 miles west of Oroville. The Thermalito Powerplant has four units with a maximum flow 17,400 cfs and a maximum water head of about 102 feet with a maximum energy requirement of 120 MW. The energy factor is about 83 kWh/af with an efficiency of about 82%. The pumping units lift water about 100 feet at a maximum flow of 9,120 cfs with a pumping energy factor of 119 kWh/af and a pumping efficiency of about 84%.

21.1.2.2 SWP Delta Facilities

The Harvey O. Banks Pumping Plant in the south Delta pumps water into the California Aqueduct (CA). The pumping plant utilizes 11 pumps; two are rated at 375 cfs capacity, five at 1,130 cfs capacity, and four at 1,067 cfs capacity. The plant lifts the water about 252 feet from the Clifton Court Forebay into the California Aqueduct. The maximum pumping capacity is about 10,670 cfs. The maximum energy requirement is about 246 MW. The pumping energy factor is about 279 kWh/af with an efficiency of 90%. Pumping is scheduled to be at maximum capacity during off-peak hours each day; the Clifton Court Forebay storage capacity of about 10 TAF allows this basic operational strategy.

The Barker Slough Pumping Plant diverts water from Barker Slough into the North Bay Aqueduct for use by SWP contractors in Napa and Solano Counties. The current Barker Slough Pumping Plant capacity is about 150 cfs with an energy requirement of about 4 MW. The Cordelia Pumping Plant has a capacity of about 130 cfs with an energy requirement of about 4 MW. The South Bay Pumping Plant is located near the Banks Pumping Plant and pumps water about 566 feet to the South Bay Aqueduct. The South Bay Pumping Plant has nine units with a maximum flow of 330 cfs. Four additional units are currently under construction (completed in 2012) with an additional capacity of 180 cfs. The current energy requirement of 21 MW will therefore increase to 27 MW. The pumping energy factor is about 759 kWh/af with an efficiency of about 75% (California Department of Water Resources 2010).

21.1.2.3 San Luis Reservoir and Canal Facilities

The San Luis Unit was constructed in the 1960s and is jointly operated by DWR and Reclamation. The San Luis Reservoir has a maximum capacity of about 2,000 TAF (Bureau of Reclamation 2012). The William R. Gianelli Pumping-Generating Plant lifts water from the O'Neill Forebay to the San Luis Reservoir in the fall and winter months when water demands are reduced. San Luis Reservoir provides seasonal storage for CVP and SWP water. When water demands increase in the spring and summer months, water is released through the generating units to O'Neill Forebay and the San Luis Canal (part of the California Aqueduct). The plant energy factors have been described under the CVP facilities.

The Dos Amigos Pumping Plant is located along the San Luis Canal 17 miles south of the O'Neill Forebay. The Dos Amigos Pumping Plant lifts water approximately 125 feet. The pumping capacity is 15,450 cfs with an energy requirement of about 179 MW. The pumping energy factor is 140 kWh/af and the pumping efficiency is about 89%. The Coastal Aqueduct connects to the California Aqueduct near Kettleman City, California, and delivers water to the Central Coast. Water is pumped through the Las Perillas, Badger Hill, Devil's Den, Bluestone, and Polonio Pass Pumping Plants. The Las Perillas Pumping Plant lifts water about 55 feet from the California Aqueduct to the first section of the coastal branch. The plant contains six pumping units with a capacity of about 461 cfs and an energy requirement of 3 MW. The Badger Hill Pumping Plant contains six pumping units that lift water 151 feet with a capacity of about 500 cfs and an energy requirement of 9 MW. Three pumping plants (Devil's Den, Bluestone and Poloniao) lift water a total of 1,500 feet in a pipeline with a capacity of 130 cfs. The combined pumping energy requirement for these three plants is 24 MW. The pumping efficiency for these plants is about 75% with an energy factor of 2,000 kWh/af.

21.1.2.4 California Aqueduct Facilities

Some water is delivered to Kern County SWP contractors before reaching the Buena Vista Pumping Plant. All other water flowing to southern California SWP contractors must be lifted at several pumping plants over the Tehachapi Mountains. The Buena Vista Pumping Plant is about 24 miles southwest of Bakersfield. The plant contains ten pumping units with maximum capacity of 5,405 cfs that lift the water 205 feet. The energy requirement is about 108 MW with an energy factor of 241 kWh/af and an efficiency of 85%. The John R. Teerink Pumping Plant contains nine units that lift a maximum of 5,445 cfs about 233 feet. The plant energy requirement is about 112 MW with an energy factor of 249 kWh/af with an efficiency of 94%. The Ira J. Chrisman Wind Gap Pumping Plant contains nine units that lift a maximum of 4,995 cfs about 518 feet. The plant energy requirement is about 246 MW with an energy factor of 596 kWh/af with an efficiency of 87%. The A. D. Edmonston Pumping Plant is the highest lift pumping plant in the United States, pumping water over the Tehachapi Mountains to Southern California. The plant contains 14 pumping units each with four-stage impellers. The plant lifts water 1,926 feet and has a maximum capacity of 4,480 cfs. The energy requirement for the Edmonston Pumping Plant is 835 MW. The pumping energy factor is 2,256 kWh/af with an efficiency of about 85%.

The California Aqueduct continues over the Tehachapi Mountains into Southern California and splits into two branches—the East Branch and West Branch. The West Branch delivers water to Lake Castaic and provides water to western Los Angeles County and vicinity. The East Branch delivers water to the Antelope Valley, San Bernardino/Riverside areas, and eventually to Lake Perris near Hemet. The Oso Pumping Plant is the first major structure on the West Branch of the California Aqueduct. The plant is located approximately 7 miles east of Gorman. The plant lifts water 231 feet and has a maximum capacity of 3,252 cfs. The energy requirement is about 70 MW. The pumping energy factor is about 260 kWh/af with an efficiency of about 89%. The west branch water then flows to Pyramid Lake through the Warne Powerplant. The William E. Warne Powerplant is located at Pyramid Lake. The plant contains two units with a capacity of 1,500 cfs. The water head is about 740 feet. The generation capacity is 74 MW with an energy factor of 570 kWh/af and an efficiency of about 77%. The Warne Powerplant recovers some of the energy used to pump West Branch aqueduct water over the Tehachapi Mountains. The Castaic Powerplant is owned and operated by the Los Angeles Department of Water and Power (LADWP). The plant is located between Pyramid Lake and the Elderberry Forebay within Castaic Lake. The Castaic Powerplant is operated as a pump-back facility, providing peaking generation for LADWP. The plant contains seven generating units with a maximum flow of 3,470 cfs and a generating capacity of 1,250 MW. Six pumping units lift water about 1,075 feet with a combined capacity of 2,300 cfs. The pumping units require a total of 1,450 MW.

The Alamo Powerplant is on the East Branch of the California Aqueduct. The plant has a head of about 140 feet with a flow of 1,740 cfs that generates about 17 MW. The energy factor is about 120 kWh/af with an efficiency of about 85%. The Pearblossom Pumping Plant is on the East Branch, about 25 miles west of Lancaster. The plant contains nine pumping units with a combined capacity of 2,575 cfs with a pumping head of 540 feet. Aqueduct capacity restrictions limit the flow to about 2,000 cfs. The energy requirement for a flow of 2,000 cfs is about 120 MW with an energy factor of about 712 kWh/af and an efficiency of 76%. The Mojave Siphon Powerplant is located at Silverwood Lake. The plant is operated at a maximum flow of 2,000 cfs due to aqueduct restrictions. The generating capacity at 2,000 cfs with a maximum head of 135 feet (Silverwood Lake at low elevation) is about 23 MW. The energy factor is about 115 kWh/af and the efficiency is about 85%. Water from Silverwood Lake flows through the San Bernardino Tunnel to the Devil Canyon Powerplant, 5 miles north of San Bernardino. The plant contains four units with a maximum flow of 2,600 cfs due to capacity restrictions at the afterbay. The water head is 1,400 feet and the maximum generation capacity is 235 MW. The energy factor is 1,150 kWh/af with an efficiency of about 82%.

21.1.3 CVP and SWP Energy Generation and Pumping Use

The generation of electrical energy at the CVP and SWP generating plants is dependent on the water runoff conditions and therefore can vary greatly from year to year. Tables 21-1, 21-2, 21-5, and 21-6 provide summaries of CVP and SWP hydropower generation capacities, but the monthly water flows (TAF) are needed to calculate the energy that would be generated (GWh) each month. Each of the generating plants has a water flow capacity, and high flows would spill (be released through other gates or spillways). The CVP and SWP facilities have been designed to utilize the majority of the flows at each generating plant. The energy required to pump and deliver water from the Delta to the CVP and SWP water contractors is totally dependent on the volume of water delivered each month and the pumping plants that are needed to deliver the water to the contractors. Because the percentage of each year's water supply that is delivered to each CVP and SWP contractor is relatively constant, and the pumping energy required to seasonally store water in San Luis or to deliver water to each contractor is constant, the total monthly energy requirement for CVP and SWP pumping can be estimated from the annual CVP and SWP pumping from the Delta.

21.1.3.1 CVP and SWP Energy Generation

For planning purposes such as this energy evaluation of the BDCP alternatives, the monthly CVP and SWP energy generation can be estimated from the monthly flows (TAF) and reservoir storage (TAF) simulated with the CALSIM-II model for each BDCP alternative. The CALSIM-II model is a water resources simulation planning tool developed jointly by DWR and Reclamation. The CALSIM-II model is applied to the SWP, the CVP, and the Delta. The model is designed to evaluate the performance of the CVP and SWP systems for: existing or future levels of land development, potential future facilities, and current or alternative operational policies and regulatory environments. Key model output includes reservoir storage, in-stream river flow, water delivery, Delta exports and conditions, biological indicators, and operational and regulatory metrics. CALSIM-II represents the best available planning model for the CVP-SWP system.

CVP and SWP water deliveries are simulated, in CALSIM-II, based on a method that estimates the actual forecast allocation process. The North of Delta (NOD) and South of Delta (SOD) deliveries for both the CVP and SWP contractors are determined using a set of rules for governing the allocation of water. CALSIM-II uses a water supply and water demand relationship to find delivery quantities given available water, operational constraints, and desired reservoir carryover storage volumes. CALSIM-II simulates a suite of environments to represent the CVP and SWP systems. The regulatory environments consist of the SWRCB D-1641 (also referred to as the 1995 Water Quality Control Plan "WQCP"), and the CVPIA (b)(2) regulatory environment which implements fish protection actions and the Joint Point of Diversion (JPOD) where water is exported or "wheeled" at the Delta pumping facilities.

Given the relatively generalized representation in CALSIM-II model of the complex physical operational environment of the SWP, CVP, and the Delta, caution is required when interpreting outputs from the model results as a basis for trying to predict energy consumption associated with water deliveries. The CALSIM-II model is not designed to reproduce actual historical operations of the different SWP and CVP system power generation and pumping plants. Also, different regulatory environment settings in the CALSIM-II model would produce different allocations and system water deliveries, thereby also incidentally affecting energy consumption. For these reasons, CALSIM-II outputs represent a good starting place for assessing power consumption for related water deliveries. In DWR's experience, the CALSIM-II outputs tend to overstate, rather than understate, actual power consumption, and thus analysis tends to err on the side of overstating impacts.

Results from the CALSIM-II modeling indicate that the basic operation of each of the CVP and SWP reservoirs is largely determined by the reservoir inflow, the maximum reservoir storage (flood control) values, and the minimum downstream flow requirements for each reservoir. The seasonal energy generation follows the seasonal inflows and reservoir storage patterns. The generation energy factor (MWh/TAF) for each reservoir is highest when the reservoir is full, but the seasonal range of water heads (reservoir elevation minus tailwater elevation) is generally about 75% of the maximum value in most years. Only in a few dry year sequences (about 10% of the years) are the Trinity or Shasta storage levels low enough to reduce the water head to less than 50% of the maximum head. The monthly reservoir inflows (and releases) vary much more dramatically from the spring runoff months to the low flow summer months or between wet and dry years.

There are some variations in the seasonal storage and release patterns for a given year between alternatives, but the energy generation for each year is largely determined by the reservoir inflows. There are therefore very few differences in the monthly and annual upstream CVP and SWP energy generation patterns between the BDCP alternatives. The small changes in the monthly reservoir release patterns between alternatives will cause only small changes in the energy generation. Therefore, the only substantial changes in the CVP and SWP energy generation patterns will be caused by the assumed future effects of climate change on altered runoff patterns.

The energy generation calculations based on upstream reservoir operations (storage and release flows) will be demonstrated as an example for the Existing Conditions (2010) for the upstream CVP and SWP Powerplants. The maximum monthly generation depends on the monthly release flow (TAF) and the reservoir storage (TAF) which controls the water head and corresponding energy factor. The BDCP energy analysis assumes that the upstream energy generation at the CVP and SWP facilities would not change for the different baselines (i.e., Existing Conditions under CEQA and No Action Alternative under NEPA) since this is based on runoff and reservoir elevations, and would not change for the BDCP alternatives. Therefore, only energy uses for pumping at the proposed North Delta pumping plants and at the existing CVP and SWP Delta and south of Delta pumping plants are evaluated for each of the BDCP alternatives. The energy generation values shown in the following monthly tables provide examples of the variations in the monthly generation caused by changes in hydrology at each CVP and SWP facility for Existing Conditions; the monthly generation for the No Action Alternative would be very similar.

Table 21-7a shows the monthly cumulative distributions of Trinity Reservoir storage (TAF) for Existing Conditions (with historical inflows) as simulated by CALSIM-II for 1922–2003. The maximum storage was about 2,400 TAF in May and June of a few years. The minimum storage was about 240 TAF (10% of maximum storage) in the fall months of a few years.

Table 21-7a. CALSIM-II -Simulated Monthly Cumulative Distributions of Trinity Storage (TAF) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Minimum	240	240	242	250	267	355	476	533	551	541	414	276
10%	633	667	684	675	764	812	974	1,077	1,029	946	785	680
20%	895	890	926	1,027	1,019	1,146	1,288	1,319	1,270	1,188	1,047	951
30%	1,102	1,099	1,132	1,197	1,296	1,410	1,527	1,558	1,512	1,518	1,308	1,185
40%	1,241	1,216	1,252	1,316	1,422	1,601	1,747	1,819	1,740	1,641	1,461	1,320
50%	1,370	1,341	1,374	1,446	1,617	1,718	1,879	1,956	1,867	1,755	1,608	1,446
60%	1,460	1,421	1,577	1,715	1,758	1,872	2,035	2,066	1,995	1,866	1,696	1,552
70%	1,693	1,681	1,750	1,786	1,868	2,017	2,159	2,213	2,154	2,057	1,925	1,800
80%	1,909	1,838	1,838	1,866	1,950	2,050	2,178	2,259	2,263	2,226	2,116	2,004
90%	1,913	1,850	1,850	1,875	1,950	2,050	2,195	2,310	2,361	2,319	2,210	2,063
Maximum	1,913	1,850	1,850	1,875	2,054	2,154	2,200	2,360	2,434	2,359	2,210	2,063
Average	1,336	1,307	1,338	1,396	1,483	1,600	1,738	1,810	1,790	1,703	1,564	1,432

Table 21-7b shows the monthly cumulative distributions of the calculated Trinity Powerplant water head (feet) for Existing Conditions. The surface elevation is estimated from an equation that was determined from the Trinity Reservoir elevation and volume. The equation includes a factor unique to the facility based on the actual relationship to storage volume and reservoir elevation. In the equation below, the value of 2.47 is unique to Trinity; other reservoirs have their own conversion factors. The equation for Trinity elevation (similar for each reservoir) is:

Surface elevation (feet) = 2.47 x storage (acre-feet [af]) ^ 0.3509 + 1,940 (base elevation)

Table 21-7b. Monthly Cumulative Distributions of Estimated Trinity Reservoir Head (feet) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Minimum	231	231	231	233	238	259	283	293	295	294	271	241
10%	308	313	316	314	326	333	352	363	358	349	329	315
20%	343	342	347	358	357	370	384	387	382	374	360	349
30%	366	365	369	375	385	395	405	408	404	405	386	374
40%	380	377	381	387	396	411	423	428	422	415	400	387
50%	392	389	392	398	413	421	433	438	432	424	412	398
60%	400	396	409	420	424	432	444	446	441	432	419	407
70%	419	418	423	426	432	443	452	456	452	445	436	427
80%	435	430	430	432	438	445	454	459	459	457	450	442
90%	435	431	431	433	438	445	455	462	466	463	456	446
Maximum	435	431	431	433	445	452	455	466	470	465	456	446
Average	389	386	389	394	402	411	422	428	426	420	408	397

The tailwater elevation for the Trinity Powerplant (upstream end of Lewiston Reservoir) is normally about 1,900 feet. The maximum head for the Trinity Powerplant was about 470 feet and the median monthly heads range from 390 feet in the fall months to 430 feet in the spring months when the reservoir is highest. The minimum head was about 230 feet. The generating plant cannot operate below a minimum water elevation (penstock opening).

Table 21-7c shows the monthly cumulative distributions of Trinity Powerplant release flow (TAF) for the No Action Alternative as simulated by CALSIM-II for 1922–2003. Because the maximum penstock flow is about 4,200 cfs (260 TAF per month) there are some months with flow that must be released from the river gates, without generating energy. Most of the release flows were in the spring and summer months. Releases were made in every month to supply Trinity River flows below Lewiston Reservoir. The Trinity generating plant was at maximum capacity in May for about half of the years. This is the month with the peak flow requirements for the Trinity River.

Table 21-7c. CALSIM-II simulated Monthly Cumulative Distributions of Trinity Powerplant Flow (TAF) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	12	9	16	16	14	16	24	98	55	44	43	39	576
10%	38	18	18	18	16	17	27	171	61	120	99	76	812
20%	38	18	18	18	16	18	34	187	91	130	120	86	972
30%	69	24	24	24	18	18	36	195	121	151	120	116	1,011
40%	69	24	24	24	22	24	41	256	137	160	123	116	1,064
50%	69	37	25	25	22	24	45	257	149	160	135	116	1,130
60%	94	47	33	34	22	30	51	260	152	160	151	146	1,197
70%	119	47	34	51	30	33	56	260	169	172	151	146	1,288
80%	133	48	34	93	32	61	61	260	194	191	194	171	1,410
90%	147	54	86	160	65	114	101	260	252	231	222	182	1,640
Maximum	226	252	260	260	235	260	172	260	252	260	231	213	2,198
Average	88	40	46	58	39	49	55	225	148	163	146	126	1,184

Table 21-7d shows the monthly cumulative distributions of calculated Trinity Powerplant energy generation (GWh) for Existing Conditions for 1922–2003. The maximum generation is about 103 MW at the maximum release flow at the highest head. The generation efficiency is about 85% and the generation energy factor is the head times the efficiency. The seasonal generation pattern can be summarized with the median monthly values; the generation is highest in May and moderately high in June-September and much less in October–April. The median annual generation for the No Action Alternative was calculated to be about 400 GWh and the average annual generation was 418 GWh. [This represents about $20 million in energy value assuming an average energy cost of $50/MWh]. The range in annual generation reflects the range in annual runoff from the Trinity watershed. The 10% cumulative annual generation was 241 GWh (0.6 x median) and the 90% cumulative annual generation was 622 GWh (1.55 x median).

Table 21-7d. Monthly Cumulative Distributions of Estimated Trinity Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	2.4	1.7	3.6	3.6	3.5	3.9	7.6	27.9	15.3	11.0	11.1	9.6	152
10%	10.4	5.4	5.3	5.0	4.6	5.2	9.5	44.6	18.8	33.0	32.0	21.8	241
20%	11.2	5.9	5.9	6.1	5.2	6.1	10.6	64.0	30.9	41.2	38.0	25.5	290
30%	19.8	6.6	7.0	7.1	6.0	6.7	13.1	70.3	43.0	52.9	44.3	36.9	347
40%	22.9	7.1	7.6	7.9	7.0	8.0	14.5	85.5	49.6	57.0	45.6	38.2	378
50%	24.3	12.0	8.2	8.8	7.6	8.7	16.2	94.7	56.7	59.1	49.6	41.7	401
60%	32.2	15.4	11.1	11.0	8.0	9.9	17.5	98.4	58.9	60.7	52.3	50.0	435
70%	37.2	15.9	11.7	17.8	10.0	11.3	19.8	100.6	60.6	62.3	54.8	52.5	479
80%	48.4	16.8	12.3	31.2	11.6	23.1	21.4	101.6	71.8	68.9	61.2	56.2	527
90%	51.0	19.6	31.4	49.1	24.2	42.9	38.9	102.3	98.2	81.6	74.1	68.1	622
Maximum	81.7	91.5	95.3	95.7	89.0	100.1	66.4	103.0	100.7	103.0	86.2	75.6	841
Average	29.1	13.4	15.9	20.2	13.9	17.8	19.9	82.3	54.7	58.0	50.1	43.2	418

Table 21-7e shows the monthly cumulative distributions of calculated Trinity Powerplant energy generation (GWh) for the No Action Alternative for 1922–2003. The average inflow was slightly more modified, with more inflow shifted into the early spring months with even less snowmelt runoff in May and June, but the release patterns and energy generation were nearly identical to the No Action Alternative. The average annual Trinity Powerplant energy generation was 415 GWh, reduced by about 1% from the No Action Alternative.

Table 21-7e. Monthly Cumulative Distributions of Estimated Trinity Powerplant Energy Generation (GWh) for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	0.0	1.7	1.8	1.8	3.6	3.7	7.7	20.8	14.0	11.4	1.3	1.4	126
10%	5.8	4.5	4.4	4.7	4.4	4.9	9.3	46.1	17.7	27.0	28.2	12.2	247
20%	10.7	6.0	5.5	5.7	5.1	6.0	11.2	64.3	31.4	36.6	37.1	23.8	274
30%	11.8	6.6	6.5	6.4	5.8	6.5	13.5	69.5	42.8	45.1	44.6	26.0	323
40%	19.5	7.1	7.1	7.2	6.6	7.4	15.3	84.1	56.9	56.5	46.0	35.4	362
50%	23.3	7.3	7.7	7.9	7.0	8.3	16.6	91.5	58.7	58.9	53.0	41.7	401
60%	24.7	15.4	10.9	11.3	7.8	9.3	18.1	97.6	70.2	59.8	54.0	50.0	440
70%	33.4	15.9	11.3	11.8	8.3	10.9	19.9	99.3	80.7	61.7	55.1	51.6	478
80%	36.2	17.3	11.8	33.3	20.1	19.7	24.5	101.1	90.4	66.4	62.2	59.1	538
90%	46.7	40.2	16.0	61.2	42.7	52.6	41.9	102.0	97.2	74.1	72.0	68.4	652
Maximum	81.7	76.1	95.3	96.7	90.7	102.2	94.0	103.0	100.7	103.0	81.2	83.7	836
Average	24.1	15.8	12.8	20.3	16.5	17.9	21.5	81.7	59.9	54.3	49.6	40.9	415

Although not shown here (see Chapter 5, *Water Supply*), the Trinity Reservoir storage patterns and the Trinity release patterns were nearly identical for all of the BDCP (operations) alternatives. The energy generation at all of the CVP and SWP generation plants was nearly identical for each of the BDCP alternatives. The only major factor affecting the monthly and annual CVP and SWP energy generation was the hydrology (inflow) conditions.

Tables 21-8a through 21-8h show the calculated monthly cumulative distribution of energy generated at each of the other major upstream CVP and SWP facilities for Existing Conditions. Table 21-8a shows the monthly generation patterns for the Carr Powerplant, and Table 21-8b shows the monthly generation patterns for the Spring Creek Powerplant. Both of these power plants are dependent on the Trinity River exports that are greatest in the summer months of July-October, with occasional exports in high flow winter months. The average annual generation was 294 GWh for the Carr Power Plant and 378 GWh for the Spring Creek Powerplant. Table 21-8c shows the monthly generation patterns for the Shasta Powerplant, and Table 21-8d shows the monthly generation patterns for the Keswick Powerplant. The Shasta generation was highest in the months of May through August, because of high reservoir elevations (i.e., head) and high releases. The annual average Shasta generation was 2,049 GWh. The Keswick generation was more uniform in all months but was highest in June–August. The annual average generation was 469 GWh. Table 21-8e shows the monthly generation patterns for Folsom and Table 21-8f shows the monthly generation for Nimbus. Both power plants had fairly uniform energy generation, with the highest generation in January–July, and the lowest generation in September. The annual average generation was 579 GWh at Folsom and 72 GWh at Nimbus. Table 21-8g shows the monthly generation patterns at the New Melones Powerplant. The highest generation was in the months of April-July, corresponding to peak snowmelt and irrigation diversions. The annual average generation was 477 gWh. Table 21-8h shows the monthly generation pattern for the Hyatt and Thermalito Power Plants (combined). These are the two SWP power plants on the Feather River. The highest generation was in the months of May through September. The lowest generation was in October-December. The annual average generation was 2,292 GWh.

Table 21-8a. Monthly Cumulative Distributions of Estimated Carr Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Min	0	0	0	0	0	0	0	0	0	0	1	0	83
10%	8	0	0	0	0	0	0	0	0	43	42	8	158
20%	8	0	0	0	0	0	0	0	0	51	51	33	199
30%	25	0	0	0	0	0	3	0	2	51	51	42	225
40%	25	3	3	3	0	3	5	0	8	51	52	49	257
50%	25	4	3	3	3	3	8	0	8	51	59	49	291
60%	25	15	8	4	3	3	10	0	25	59	68	65	318
70%	42	16	8	8	3	6	13	3	25	68	68	65	350
80%	60	16	12	20	3	8	16	8	25	75	85	82	387
90%	66	30	31	61	8	28	41	8	42	112	100	85	456
Max	112	68	59	88	31	112	86	81	105	112	112	108	643
Average	34	11	10	15	3	9	13	6	17	60	63	53	294

Table 21-8b. Monthly Cumulative Distributions of Estimated Spring Creek Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	4	0	0	0	0	0	0	0	0	0	6	3	113
10%	13	3	0	0	2	0	0	0	0	38	39	24	201
20%	14	5	1	5	5	3	0	0	0	47	47	31	263
30%	26	6	4	8	10	6	0	0	2	47	48	46	292
40%	29	11	7	16	16	13	1	1	5	48	51	46	339
50%	32	17	9	21	25	18	7	3	7	50	56	49	377
60%	45	19	16	26	28	24	15	5	15	55	63	62	407
70%	60	22	24	40	34	36	19	8	19	63	67	63	426
80%	65	25	32	51	40	44	26	10	24	80	84	73	446
90%	73	31	46	85	62	64	43	21	39	106	106	85	548
Maximum	116	90	110	138	125	131	89	109	111	117	138	104	951
Average	40	17	19	33	27	26	15	9	15	59	63	54	378

Table 21-8c. Monthly Cumulative Distributions of Estimated Shasta Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	36	39	46	0	30	43	50	79	126	102	45	32	875
10%	65	58	53	48	49	58	72	118	198	203	139	57	1,269
20%	78	74	64	60	58	69	91	133	210	236	161	72	1,456
30%	93	81	71	69	64	78	98	161	227	250	178	86	1,603
40%	101	88	75	75	72	86	115	169	238	268	197	96	1,760
50%	107	99	84	86	83	95	133	183	247	275	203	108	1,917
60%	112	121	91	96	96	109	148	201	257	291	212	136	2,281
70%	124	142	111	145	176	167	162	219	262	303	223	184	2,457
80%	139	177	195	206	385	259	183	229	276	320	232	228	2,656
90%	156	204	333	419	464	409	243	260	302	332	256	255	2,907
Maximum	194	491	509	513	489	539	532	390	413	369	301	321	3,605
Average	108	123	136	150	175	164	150	189	246	271	197	139	2,049

Table 21-8d. Monthly Cumulative Distributions of Estimated Keswick Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Min	13	15	15	15	14	15	15	17	33	40	33	15	268
10%	20	16	15	15	14	15	17	25	40	49	40	20	317
20%	23	18	15	15	14	15	20	28	43	54	42	22	338
30%	26	19	16	15	14	15	20	30	44	57	44	25	367
40%	27	21	18	18	16	18	24	32	45	59	47	26	393
50%	28	23	18	20	19	21	25	35	47	61	49	29	429
60%	29	26	20	21	19	21	28	38	49	64	50	36	492
70%	31	31	25	34	39	38	32	41	51	69	51	44	532
80%	34	40	40	48	63	55	34	42	54	69	55	54	580
90%	40	44	69	70	63	70	52	50	57	69	59	59	677
Max	46	68	70	70	63	70	68	70	68	70	66	68	934
Average	29	28	31	38	43	39	31	36	48	61	49	36	469

Table 21-8e. Monthly Cumulative Distributions of Estimated Folsom Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Min	5	5	6	10	8	4	4	4	4	4	4	3	76
10%	11	11	11	12	16	14	15	15	20	23	14	12	250
20%	20	20	20	21	19	17	23	20	26	43	20	18	323
30%	22	23	24	25	21	25	26	25	31	49	30	23	372
40%	23	28	30	27	27	29	32	32	39	55	36	29	474
50%	24	30	31	28	43	40	40	49	47	68	40	37	556
60%	25	34	31	43	68	56	50	62	53	75	46	45	665
70%	25	48	32	75	84	70	71	74	70	80	52	63	720
80%	25	53	52	105	108	91	85	89	85	85	63	68	807
90%	27	67	110	121	116	130	111	148	124	87	70	75	922
Max	57	125	129	129	117	134	136	148	143	111	78	80	1,328
Average	23	38	41	53	57	54	53	60	58	61	42	41	579

Table 21-8f. Monthly Cumulative Distributions of Estimated Nimbus Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Min	0.9	0.9	0.9	1.5	1.3	0.6	0.6	0.6	0.6	0.7	0.6	0.6	12
10%	1.5	1.4	1.5	1.5	1.9	1.6	1.8	1.8	2.2	3.2	1.8	1.6	31
20%	2.6	2.5	2.6	2.8	2.4	2.0	2.5	2.2	3.1	4.8	2.7	2.4	38
30%	2.8	2.9	3.1	3.1	2.4	2.8	2.9	2.7	3.1	5.4	3.4	2.7	44
40%	2.8	3.4	3.7	3.1	3.1	3.2	3.3	3.2	4.1	5.9	4.2	3.5	53
50%	2.8	3.6	3.7	3.2	4.9	4.5	4.3	5.1	4.9	7.0	4.6	4.3	61
60%	2.8	4.0	3.7	5.0	7.8	6.2	5.3	6.2	5.4	8.5	5.2	5.4	73
70%	2.8	5.5	3.7	8.5	8.3	7.7	7.4	7.4	7.0	9.2	5.9	7.0	93
80%	2.8	6.3	5.9	9.2	8.3	9.2	8.9	8.9	8.9	9.2	6.7	7.6	109
90%	3.1	7.8	9.2	9.2	8.3	9.2	8.9	9.2	8.9	9.2	7.4	8.5	124
Max	6.2	8.9	9.2	9.2	8.3	9.2	8.9	9.2	8.9	9.2	8.2	8.9	183
Average	2.7	4.9	6.0	8.1	8.3	6.8	5.8	6.4	6.3	6.7	4.7	4.8	72

Table 21-8g. Monthly Cumulative Distributions of Estimated New Melones Powerplant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Min	6	3	1	0	0	4	18	36	27	29	29	17	214
10%	14	8	7	3	2	11	45	47	35	38	35	21	298
20%	21	9	8	5	5	16	51	54	41	43	42	23	339
30%	24	9	8	8	6	22	58	61	43	45	44	26	376
40%	26	9	9	8	9	28	62	66	46	48	47	27	394
50%	28	11	9	9	11	34	69	78	50	49	48	29	429
60%	31	13	10	10	13	43	77	85	69	57	52	32	481
70%	33	14	11	10	15	51	81	89	78	62	57	35	523
80%	35	16	13	15	19	56	83	94	84	68	62	38	573
90%	40	19	14	15	31	62	89	101	86	72	65	43	729
Max	54	94	138	221	161	162	100	117	201	197	127	94	1,390
Average	28	14	13	16	18	39	68	75	62	58	53	34	477

Table 21-8h. Monthly Cumulative Distributions of Estimated Hyatt and Thermalito (combined) Power Plant Energy Generation (GWh) for Existing Conditions

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	26	20	21	19	20	19	47	54	109	40	40	33	721
10%	36	25	26	23	31	24	72	103	141	219	80	56	1,183
20%	41	33	42	28	40	39	92	118	155	295	143	75	1,447
30%	68	49	54	46	50	58	97	125	173	354	194	116	1,559
40%	89	55	56	55	54	73	105	127	190	395	261	148	1,815
50%	114	70	59	58	57	138	116	133	212	415	273	160	1,985
60%	131	82	92	59	103	201	126	139	234	424	300	255	2,470
70%	142	85	121	67	212	248	153	193	250	451	310	320	2,880
80%	156	89	156	199	379	357	226	329	271	471	325	376	3,337
90%	169	94	229	540	563	549	358	481	350	490	336	416	3,581
Maximum	223	561	670	669	623	671	666	698	569	508	377	441	4,777
Average	107	75	119	148	182	203	170	216	232	380	244	217	2,292

21.1.3.2 CVP and SWP Energy Use for Water Pumping

The monthly CVP and SWP energy use for pumping water from the Delta into the Delta-Mendota Canal and California Aqueduct can be reliably estimated from the monthly pumping flows (TAF) at each of the CVP and SWP pumping plants. The pumping energy used at the Gianelli Pumping Plant to seasonally store CVP and SWP water in San Luis Reservoir depends on the San Luis Reservoir elevation (water head) estimated from storage. There is some generation of energy at the Gianelli and O'Neill Power Plant as water is released from San Luis Reservoir during the summer months. There is considerable generation of energy at other SWP power plants along the East and West Aqueducts, which recover some of the energy required to pump water over the Tehachapi Mountains. The net energy required for CVP pumping and for SWP pumping can be calculated from the monthly sequence of flows simulated by CALSIM-II for each alternative. As discussed in Section 21.1, *Environmental Setting/Affected Environment*, the energy calculations based on CALSIM-II presented in this chapter represent a reasonable, though overestimated, assessment of actual energy requirements for the BDCP alternatives.

The net energy use for CVP deliveries and SWP deliveries can be calculated from the average CVP Jones pumping (TAF/yr) and the average SWP Banks Pumping. The distribution of CVP water to each contractor is somewhat variable from year to year but the average energy use reflects the normal portion of the deliveries that are seasonally stored in San Luis Reservoir. The Existing Conditions CALSIM-II results were used as an example of the baseline to calculate the CVP and SWP energy generation and pumping uses for south of Delta CVP and SWP water deliveries. The energy analysis assumes that the upstream operations and energy generation for Existing Conditions and the No Action Alternative (2060) would be the same since upstream generation is a function of runoff and reservoir elevations. The net energy use factor (MWh/TAF) for south of Delta CVP and SWP water deliveries is assumed to remain the same for each of the other baselines and for each of the BDCP alternatives; the energy use for south of Delta water deliveries will vary with the annual deliveries. Because each of the baselines have different average annual water deliveries, the CEQA

Existing Conditions (2010) and the NEPA No Action Alternative (2060) each have slightly different average energy uses for south of Delta water deliveries.

21.1.4 Energy Transmission for the BDCP Pumping Plants

In California, energy is generated throughout the state and is owned or sold to utility companies within defined areas of service and other users. Electric energy is distributed to consumers by the electrical grid, which is made up of transmission lines (High Voltage for long distance) and distribution lines (Low Voltage for short distance). Substations take high voltage energy from the transmission lines and reduce the voltage for distribution lines. There are several Balancing Authorities (BA) that operate within the state, including the CAISO and Balancing Authority of Northern California (BANC). The BAs are responsible for ensuring there are sufficient resources to balance the grid within their jurisdictional areas. The CAISO provides transmission access and a power market within its BA Area. Scheduling and management of transmission and energy for the BDCP would be similar to scheduling and management of transmission and energy for the CVP and SWP pumping plants in the south Delta. The additional energy needed for the BDCP alternatives would be provided from the power portfolios of SWP and CVP and in proportion to their participation in BDCP. Energy needed for pumping water would be provided from a mix of CVP and SWP hydroelectric generation, power purchase contracts, power exchanges, and power markets.

Three electric utilities could potentially provide transmission interconnection and service to support the supply of power to the BDCP: Sacramento Municipal Utility District (SMUD), Pacific Gas and Electric Company (PG&E) (under the CAISO BA) and Western. DWR has the flexibility to regulate SWP pumping on an hourly basis and thus manages the system to make the most economic decisions for acquisition of power. By scheduling as much off-peak pumping as possible, DWR is able to take advantage of less expensive surplus electrical generation. Conversely, DWR maximizes its power generation for the benefit of the interconnected electrical grid during the on-peak hours when electrical demand is highest. In this manner, DWR is able to manage a comprehensive power resources program that helps minimize the cost of water deliveries to SWP water supply contractors while maximizing the benefits of the statewide electrical grid.

DWR will conduct a System Impact Study which will evaluate the electrical transmission and power needed for the conveyance facilities. The study will be completed in time to procure the necessary power to support construction and operation of the facilities. Typically, DWR's power and planning process begins with a review of all projected loads and resources including pump load, generation from DWR's facilities, generation from joint facilities, sales purchases, and exchanges. The net of these loads and resources yields a power portfolio in which DWR often has a net deficit during the off-peak hours and a net surplus during the on-peak hours. This System Impact Study for BDCP is expected to take between five and seven years. Impacts that may result from the construction and operation of new transmission infrastructure are addressed throughout the individual resource sections.

Electrical power for new north Delta pumping plant facilities would be delivered through a single 230 kV transmission line, owned by either a utility or the BDCP, which would interconnect with either Western or PG&E at a new or existing utility substation depending on the conveyance alignment and whichever utility can provide the requisite transmission facilities, connections, and service according to the construction schedule. Some utility grid upgrade would likely be needed to accommodate this large new pumping energy requirement. The new or upgraded transmission line would terminate at the new 230 kV substation that would be constructed as part of the BDCP. There, the electrical power would be transformed from 230 kV to 69 kV and delivered on new overhead 69 kV transmission lines to the pumping plants.

21.2 Regulatory Setting

Energy generation at CVP facilities is managed by Western. SWP energy generation is managed and sold by DWR. Regulations applicable to energy generation and transmission that are relevant to evaluating the potential impacts of the BDCP alternatives on energy generation and use are discussed in this section.

21.2.1 Federal Plans, Policies, and Regulations

21.2.1.1 Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) regulates transmission of oil, natural gas, and electricity in interstate commerce. FERC also licenses and inspects private, municipal, and state hydropower projects, and supervises environmental concerns related to hydroelectricity and major electricity policy initiatives. FERC monitors and investigates energy markets and ensures the reliability of interstate transmission systems (Federal Energy Regulatory Commission 2006). The energy utilities in the Delta region are subject to the regulations of FERC.

FERC passed Order No. 888 and Order No. 889 in April 1996. These orders work to establish fair competition of the wholesale power marketplace and establish lower cost power for consumers in the United States. Order No. 888 requires utilities that own, control, or operate interstate electric energy transmission facilities to have open access, nondiscriminatory tariffs on transmission. Order No. 888 also allows public utilities and transmitting utilities to seek the recovery of stranded costs associated with providing open access and Federal Power Act Section 211 transmission services. Order No. 889 requires public utilities and transmitting utilities that own, control, or operate interstate electric energy transmission facilities to create or participate in an Open Access Same-Time Information System program. Such programs provide existing and potential open access transmission customers with available transmission capacity, price, and additional information to enable them to obtain open access nondiscriminatory transmission service (Federal Energy Regulatory Commission 2009a, 2009b).

Licensing for Oroville Facilities

DWR is currently implementing the Settlement Agreement developed during the FERC relicensing process for the Oroville facilities on the Feather River to continue to own, operate, and maintain them. FERC has the authority to license the construction and operation of non-federal hydroelectric development. Although no additional facilities are planned for Oroville, DWR's license application proposes several programs to enhance habitats, improve recreational use of the facilities, and address the protection of cultural resources (California Department of Water Resources 2006). Oroville is the only facility in the study area to have recently undergone the relicensing process.

21.2.1.2 Western Area Power Administration

Western markets and delivers power from multiuse water projects that are operated by Reclamation, the U.S. Army Corps of Engineers (USACE), and the International Boundary and Water

Commission. Western markets and delivers CVP's installed capacity of 2,099 MW through 865 circuit-miles of transmission lines (Western Area Power Administration 2009). Western is organized into five regions throughout the western and central United States. The CVP is within Western's Sierra Nevada Region.

21.2.1.3 Other

Many of the energy operations within the Delta are subject to the following federal acts: the Rivers and Harbors Appropriation Act of 1899, Section 10; the Rivers and Harbors Act of 1935; the Rivers and Harbors Act of 1937; the Rivers and Harbors Act of 1940; the Auburn-Folsom South Unit Authorization Agreement; the Emergency Relief Appropriation Act of 1935; the Flood Control Act of 1944; the Federal Endangered Species Act; and the Central Valley Project Improvement Act (CVPIA) Section 3406 (b)(2). The Rivers and Harbors Appropriation Act of 1899 assigned the USACE responsibility for the regulation of navigable waters of the United States. In 1935, the federal government approved the Emergency Relief Appropriation Act and in doing so approved $20 million in Emergency Relief Funds for the CVP. The Flood Control Act of 1944 approved the construction of the Shasta, Folsom, and New Melones Dams for the CVP.

The Rivers and Harbors Act of 1937 reauthorized the CVP and stated purposes of the project. Energy operations within the statutory Delta are also subject to regulations within the CVPIA. These acts are discussed further in Chapter 5, *Water Supply*, Section 5.2.1. Congress adopted the Auburn-Folsom South Unit Authorization Agreement in 1965 to authorize the construction and operation of the Auburn-Folsom South Unit and the development of recreational facilities associated with the unit. This agreement is further discussed in Chapter 5, *Water Supply*, Section 5.2.1. Energy operations are also subject to the Federal Endangered Species Act, which is discussed in Chapter 11, *Fish and Aquatic Resources*, Section 11.2.1.1, and Chapter 12, *Terrestrial Biological Resources*, Section 12.2.1.2.

21.2.2 State Plans, Policies, and Regulations

21.2.2.1 California Public Utilities Commission

The California Public Utilities Commission (CPUC) regulates utilities to establish safe and reliable utility service, protect consumers against fraud, provide service at reasonable costs, and promote a healthy state economy. The CPUC regulates privately owned natural gas, electric, telecommunications, water, railroad, rail transit, and passenger transportation companies (California Public Utilities Commission 2007). The CPUC does not, however, regulate CVP or SWP energy facilities or pumping plants.

21.2.2.2 California Independent System Operator

CAISO was created in 1996 by an act of California Legislature and became operational in 1998 as a not-for-profit public benefit corporation to act as the independent operator of California's transmission grid. While transmission lines remain owned by utility companies, CAISO ensures that non-discriminatory open access to transmission service is available to all users. Starting in 2009, CAISO manages transmission congestion through use of locational marginal pricing and manages an integrated forward market for energy purchases and sales. Additionally, CAISO coordinates transmission usage and energy flows with neighboring Balancing Authorities. (California Independent System Operator 2009).

21.2.2.3 California Energy Commission

The Warren-Alquist Energy Resources Conservation and Delivery Act, also called the Warren-Alquist Act, was passed in 1974. The Warren-Alquist Act established the CEC and granted it statutory authority (California Energy Commission 2009b).The CEC promotes energy efficiency throughout the state, supports renewable energy and public interest energy research, and plans and directs the state's responses to energy emergencies. The CEC provides one-stop permitting for new energy facilities. The CEC also regulates the state's energy operations and provides funds for a variety of technologies that would reduce greenhouse gases (GHGs) (California Energy Commission 2009a).

21.2.2.4 CEQA Guidelines

State CEQA guidelines Appendix F, *Energy Conservation*, outlines analysis requirements for the evaluation of potential energy impacts of proposed projects. Particular emphasis is placed on "avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy." Moreover, the CEQA guidelines state that significant energy impacts should be "considered in an EIR to the extent relevant and applicable to the project." The review of potential impacts should include a discussion of project energy requirements, effects on local and regional energy supplies, effects on peak and base period demands, compliance with energy standards, and effects on energy resources. Alternatives should be compared in terms of total and inefficient energy use. Mitigation for potential significant energy impacts could include a variety of strategies, including measures to reduce wasteful energy consumption and project siting.

21.3 Environmental Consequences

This section describes the potential effects of the BDCP alternatives on energy generation at CVP and SWP hydropower facilities and energy uses for water supply pumping plants. The estimated electrical energy required for construction of the water conveyance facilities associated with BDCP are also described. The relatively large energy requirements for pumping CVP and especially SWP water supplies from the Delta are well described and understood (California Energy Commission 2005; Natural Resources Defense Council 2004).

Effects on energy production and use have been evaluated for the existing CVP and SWP facilities, as well as the additional BDCP conveyance and pumping facilities. The existing transmission lines, switching stations, and substations have been designed and constructed to accommodate the normal seasonal patterns of energy generation at the CVP and SWP hydropower facilities and the electrical energy uses at water supply pumping plants. Because the additional energy requirements for the BDCP conveyance facilities are moderate relative to the normal seasonal energy transmission capacity, there would not likely be any substantial impacts on electrical grid capacity or electrical grid reliability associated with the increased energy uses for the BDCP alternatives.

The potential effects of the BDCP are discussed under 2025 and 2060 conditions. Potential effects of climate change on hydrology (runoff and sea level rise) may modify BDCP operations and cause the BDCP alternatives to have slightly different energy effects within these two future periods. Results from the monthly CALSIM-II water resources model were used to provide the monthly flows and diversions for each BDCP alternative at each time frame so that monthly and annual electrical energy budgets could be calculated and compared.

The following energy effects have been evaluated.

- Monthly or annual changes in hydroelectric energy generation that would affect the regional energy supply.
- Monthly or annual increases in energy consumption (pumping) that would affect the regional energy consumption.
- Monthly or annual changes in energy use that would cause additional energy generation at facilities with higher pollutant or GHGs emissions during operation (or construction). These are considered more fully in Chapter 22, *Air Quality and Greenhouse Gases*, Sections 22.3.3.2 through 22.3.3.16.

21.3.1 Methods for Analysis

This section discusses the methods to analyze the electrical energy required for the construction of the water conveyance facilities (CM1) and the additional energy required for pumping at the alternative BDCP north Delta intakes and associated conveyance facilities. The additional energy would be related to the monthly north Delta pumping patterns for each alternative, and would depend on the hydraulic head losses associated with each conveyance alignment (pipeline/tunnel, east, or west). Larger pumps and a greater canal/tunnel capacity would be required for alternatives with higher maximum flows. The required monthly pumping energy would be proportional to the monthly water flow volume and will depend on the pumping head (lift) necessary for each conveyance alternative.

21.3.1.1 Construction

Electrical energy needs for construction were evaluated based on the estimated annual energy required for each alternative. The construction energy requirements were estimated from the facilities that would require electrical energy during construction, as described in DWR design documents for each alternative. The construction-related energy demand is considered temporary (i.e., will cease once construction is complete). Construction of the water conveyance facility would require the use of electricity for lighting, tunnel ventilation, tunnel boring, earth removal from the tunnels, and other construction machinery. Annual electrical energy use estimates for each alternative were provided by DWR and are summarized in Table 21-9.

Table 21-9. Temporary Annual Electrical Use Estimates for Construction (GWh)

Alternative	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8[a]	Year 9[a]
Alternative 1A, 2A, 6A (15,000 cfs, 2 33-ft Tunnels)	20	32	56	220	324	376	236	81	81
Alternative 4 (9,000 cfs, 2 40-ft Tunnels)	74	197	345	449	480	483	363	129	28
Alternative 7, 8 (9,000 cfs, 2 33-ft Tunnels)	13	21	45	209	314	366	231	78	78
Alternative 3 (6,000 cfs, 2 33-ft Tunnels)	10	16	40	204	308	361	228	77	77
Alternative 5 (3,000 cfs, 1 33-ft Tunnel)	7	11	24	112	170	197	124	43	43
Alternative 1C, 2C, 6C (West Alignment)	22	34	45	121	169	196	120	42	42
Alternative 1B, 2B, 6B (East Alignment)	22	41	66	83	70	62	26	18	18
Alternative 9[b] (Through Delta/ Separate Corridors)	11	21	33	42	35	31	13	-	-

- No construction

[a] DWR estimated electrical use to be one-quarter of year 5 use.

[b] DWR estimated electrical use to be one-half of Alternatives 1B, 2B, 6B (east alignment).

21.3.1.2 Operation

Energy effects from BDCP operations are generally evaluated as a reduction in the amount of hydropower energy generated or as the increase in energy use because this additional energy must be supplied from other energy sources that may have subsequent environmental consequences (land disturbance, air pollution, GHG impacts) and higher costs (economic effects). Energy effects were evaluated under 2025 and 2060 conditions because potential effects of climate change on hydrology (runoff and sea level rise) may modify the BDCP operations and cause the BDCP alternatives to have slightly different energy effects for these two future timeframes. The potential energy of a water volume that is pumped to a higher elevation is calculated as the weight of water (gravity) times the elevation difference plus losses (Total Dynamic head). Conveniently, the potential energy of 1 af of water with 1 foot of head is equal to 2,712,481 lb_f/ft^3. Also, 1 kWh of Energy is equal to 2,655,224 ft-lb_f. Therefore, the energy required to pump 1 af of water can be estimated as:

Energy (kWh/af) = 1.02* Total Dynamic Head (feet) / pumping efficiency

Pumping efficiency represent the wire to water efficiency of a Motor/pump setup and could be in the 80–90% range. For simple calculations, the formula above can be simplified by ignoring head losses (and use elevation head instead), and the 1.02 coefficient, which results in

Energy (kWh/af) = elevation head (feet) / pumping efficiency

For example, the energy required to pump water at the CVP Jones pumping plant is estimated to be about 252 kWh/af because the elevation head is about 197 feet and the efficiency is about 78% (Table 21-2). The pumping energy factor for the SWP Banks pumping plant is estimated to be about 279 kWh/af because the elevation head is about 252 feet and the efficiency is about 90% (Table 21-6).

The CALSIM-II monthly volumes (TAF) diverted (pumped) at the north Delta intakes for each BDCP alternative were used to calculate the monthly and annual energy requirements. Energy effects were then evaluated from these monthly and annual energy requirements for each BDCP alternative compared to Existing Conditions and No Action Alternative. As described above, the upstream CVP and SWP energy generation was assumed to be very similar for each of the BDCP baselines and alternatives, because the upstream reservoir operations are largely controlled by natural runoff conditions. The energy requirements for the CVP and SWP south Delta pumping plants (total Delta exports) may shift with the BDCP alternatives, because the monthly and annual exports may shift. The energy requirements for pumping and seasonal storage in San Luis Reservoir would remain similar for CVP and SWP deliveries. Therefore, the changes in energy requirements for each BDCP alternative will depend on the CALSIM-II simulated north Delta diversions and the total CVP and SWP Delta exports. The baseline (Existing Conditions or No Action Alternative) energy generation and pumping energy factor for CVP and SWP south of Delta pumping have been described in Section 21.1, *Environmental Setting/Affected Environment*.

The energy requirements were estimated from the monthly north Delta pumping operations simulated with the monthly CVP and SWP operations model (CALSIM-II) for each alternative. The monthly energy requirements were calculated by multiplying the monthly pumping volume (TAF) by the energy requirement per water volume pumped, referred to as the pumping energy factor (MWh/TAF). The pumping energy factor could be different for each alternative. The pumping energy factor for the intake pumps and for canal sections would remain constant. The pumping energy factor for a tunnel or pipeline section will increase as the flow is increased, because the head loss in a pipeline or tunnel section is proportional to the water velocity squared. The derivation of these energy factors for each alternative is summarized below.

Alternatives 1A, 2A, and 6A would include two 35-mile long tunnels with inside diameters of 33 feet, constructed between the north Forebay near Hood and the Byron Tract Forebay, adjacent to Clifton Court Forebay. Five screened intake facilities located along the Sacramento River between Freeport and Courtland, with a pumping capacity of 3,000 cfs each, would be constructed with pipelines or canals connecting these intakes and pumping plants to the north (intermediate) Forebay. The intermediate Forebay will have a water surface elevation of about 25 feet (NAVD 88 datum) and will provide temporary storage to regulate the tunnel flow and allow a pumping schedule that might vary with the tides. The intermediate Forebay provides enough energy head (water elevation) to allow some water to flow by gravity to the Byron Tract Forebay, which would have a water surface elevation of 0–5 feet. Preliminary hydraulic calculations indicate that a flow of about 3,000 cfs in each of the 33-feet diameter tunnels would be possible under gravity. Additional pumping will be required for higher flows.

The Darcy-Weisbach energy loss equation for pipes was used to estimate the head losses for the 33-feet diameter tunnels, with a Darcy friction factor of 0.0125 corresponding to relatively smooth (concrete lined) tunnels. The Darcy-Weisbach formula is:

$$\text{Energy loss (ft)} = f \times \text{Length (ft)} \times \text{Velocity}^2 / [\text{Diameter (ft)} \times 2\ g]$$

Where f is the friction coefficient (0.0125 assumed), velocity has units of ft/sec, and g is the gravitational force of 32.2 (ft/sec^2). Table 21-10 shows the energy loss calculations for a 33-feet diameter tunnel (35 miles long). This was the basis for estimating the gravity flow capacity, the capacity and lift for the low-lift pumps, and the maximum lift for the high-lift pumps (with a maximum capacity of 7,500 cfs).

Table 21-10. Energy Losses for Flow of 500 cfs to 7,500 cfs in a 35-mile Tunnel, Estimated with the Darcy-Weisbach Pipe Formula

	35-mile Tunnel 33-feet Diameter			35-mile Tunnel 40-feet Diameter	
Flow (cfs)	Velocity (ft/sec)	Energy Loss (feet)	Flow (cfs)	Velocity (ft/sec)	Energy Loss (feet)
500	0.6	0.4	500	0.4	0.1
1,000	1.2	1.5	1,000	0.8	0.6
1,500	1.8	3.3	1,500	1.2	1.3
2,000	2.3	5.9	2,000	1.6	2.3
2,500	2.9	9.3	2,500	2.0	3.5
3,000	3.5	13.4	3,000	2.4	5.1
3,500	4.1	18.2	3,500	2.8	7.0
4,000	4.7	23.8	4,000	3.2	9.1
4,500	5.3	30.1	4,500	3.6	11.5
5,000	5.8	37.1	5,000	4.0	14.2
5,500	6.4	44.9	5,500	4.4	17.2
6,000	7.0	53.5	6,000	4.8	20.4
6,500	7.6	62.8	6,500	5.2	24.0
7,000	8.2	72.8	7,000	5.6	27.8
7,500	8.8	83.6	7,500	6.0	31.9

Alternatives 1A, 2A, and 6A would have two sets of pumps at the intermediate Forebay to provide two pumping options: 1) additional energy head (lift) of about 25 feet for a total energy head of about 50 feet, which would allow a maximum flow of 4,500 cfs (capacity of low-head pumps) in each tunnel, and 2) additional energy head (lift) of 65 feet for a total energy head of about 90 feet, which would allow a maximum flow of 7,500 cfs in each tunnel. When low-head or high-head pumping is required, all the tunnel flow must be pumped. This dual-pumping design will reduce the energy required, because no intermediate pumping will be required for daily average flows of less than 6,000 cfs, and only a moderate pumping energy (25 feet) will be required for daily average flows of 6,000 cfs to 9,000 cfs. Full pumping energy (65 feet) will be required for daily flows of more than 9,000 cfs. The intake pumps will lift the water to the intermediate Forebay and this pumping energy will be required for any daily flow. Flows of less than 6,000 cfs will have a pumping energy factor of about 65 MWh/TAF, assuming an average lift of 50 feet with an efficiency of about 0.8. Flows of 6,000 cfs to 9,000 cfs will have an energy factor of about 95 MWh/TAF, and flows of more than 9,000 cfs will have an energy factor of about 145 MWh/TAF.

The CALSIM-II results for monthly pumping at the north Delta intakes were used to estimate the monthly energy use for Alternative 1A, 2A, 6A. Figure 21-3 shows the monthly north Delta pumping flows for Alternative 1A under 2025 conditions. Most of the months (75%) had flows of less than

6,000 cfs and would require only intake pumping with an energy factor of 65 MWh/TAF. About 10% of the months had flows between 6,000 cfs and 9,000 cfs, and would require intake pumping and low-head intermediate pumping with an energy factor of 95 MWh/TAF. About 10% of the months had flows of greater than 9,000 cfs and would require intake pumping and high-head intermediate pumping, with an energy factor of 145 MWh/TAF. Figure 21-4 shows the relationship between monthly pumping flow (cfs) and monthly pumping energy (GWh) for Alternative 1A under 2025 conditions. The monthly energy generally increases with monthly flow, but the slope of the relationship is greater for flows that require the low-head intermediate pumping (6,000 cfs to 9,000 cfs) or the high-head intermediate pumping (9,000 cfs to 15,000 cfs). The average energy factor for Alternative 1A under 2025 conditions was calculated to be 105 MWh/TAF, because about 37% of the water volume would require just the intake pumping, 23% of the water volume would require intake pumping and low-head intermediate pumping, and 40% of the water volume would require intake pumping and high-head intermediate pumping.

The pumping energy factors for Alternative 2A and 6A would be slightly different than for Alternative 1A because the monthly north Delta pumping flows simulated with CALSIM-II were different. The average energy factor for Alternative 2A was calculated to be about 112 MWh/TAF. The average energy factor for Alternative 6A was calculated to be about 115 MWh/TAF. More months with simulated north Delta pumping flows of greater than 6,000 cfs will increase the average energy factor for these alternatives.

Alternatives 1B, 2B and 6B include five intakes pumping to a canal section on the east side of the Sacramento River, with a water surface elevation of about 20 feet (NAVD 88). The canal would have a slope of less than 6 inches per mile (similar to the Delta-Mendota Canal and the California Aqueduct), but there would be about 2.5 miles of dual 33-feet diameter tunnels and about 3 miles of large culverts (four adjacent 26 feet x 26 feet box culverts) that would cause additional energy losses, designed for the maximum flow of 15,000 cfs. Therefore, an intermediate pumping plant with a lift of about 30 feet would be required. Because all flows will require these two pumping lifts at the intakes and at the intermediate pumping plant (50 feet total), the pumping energy factor for Alternative 1B would be about 65 MWh/TAF).

Alternatives 1C, 2C, and 6C include five intakes pumping to a canal section on the west side of the Sacramento River, with a water surface elevation of about 30 feet (NAVD 88). The canal will have a slope of less than 6 inches per mile, but there would be 17 miles of dual 33-feet diameter tunnels and about 3 miles of large culverts (four adjacent 26 feet x 26 feet box culverts) that would cause additional energy losses, designed for the maximum flow of 15,000 cfs. Therefore, an intermediate pumping plant with a lift of about 55 feet would be required. Because the canal water surface at the intermediate pumping plant will be about 15 feet (NAVD 88) and the Byron Tract Forebay elevation will be about 5 feet, there is the possibility of about 2,500 cfs of gravity flow; however Alternative 1C does not include a gravity flow bypass. Therefore, all flows will require these two pumping lifts at the intakes and at the intermediate pumping plant (85 feet total), and the pumping energy factor for Alternative 1C would be about 110 MWh/TAF.

Alternative 3 includes two intakes for a maximum capacity of 6,000 cfs. The intermediate Forebay and two 33-feet diameter tunnels would be the same as for Alternative 1A. Because a maximum of 6,000 cfs would be pumped, the tunnels would operate under gravity flow without the need for intermediate pumping. Therefore, the pumping energy factor for Alternative 3 would be about 65 MWh/TAF.

Alternative 4 includes three intakes for a maximum capacity of 9,000 cfs with the intermediate Forebay with a water surface elevation of 25 feet (NAVD 88). The two tunnels from the intermediate Forebay to the proposed expanded Clifton Court Forebay will be larger, with inside diameters of 40 feet, to allow the maximum flow of 9,000 cfs to flow in the tunnels under gravity, without the need for intermediate pumping (Table 21-10). The intake pumping energy factor would be about 65 MWh/TAF. The construction energy required for boring and spoils disposal for these larger tunnel sections would be higher (see Table 21-9). DOE has estimated that the 40-feet diameter tunnel construction energy (2,549 GWh) would be about 78% more than the electrical energy needed for construction of the water conveyance facilities associated Alternatives 1A, 2A and 6A (1,428 GWh). The additional construction energy will allow the pumping energy factor for Alternative 4 to be reduced to intake pumping alone (65 MWh/TAF). Without the larger tunnels, Alternative 4 would have required the intermediate low-head pumping plant for flows of more than 6,000 cfs; the additional energy was calculated to be about 50 GWh per year, which would be “recovered” after 25 years of Alternative 4 operation.

Alternative 5 includes one intake and one 33-feet diameter tunnel. The flow in the tunnel will be less than the gravity flow capacity (Table 21-10) so the energy factor for Alternative 5 would be about 65 MWh/TAF.

Alternatives 7 and 8 will have three intakes (9,000 cfs capacity) with two 33-feet diameter tunnels; the energy factor would be 65 MWh/TAF for flows of less than 6,000 cfs and would be 95 MWh/taf for flow of greater than 6,000 cfs. The average energy factor for Alternative 7 was calculated to be 83 MWh/taf. The average energy factor for Alternative 8 was calculated to be 86 MWh/taf. More months with simulated north Delta pumping flows of greater than 6,000 cfs will increase the average energy factor for these alternatives.

Alternative 9 requires additional pumping energy to provide a constant pumping flow of 500 cfs (1 taf per day) between tidal channels that would be separated with barriers in the south Delta. Although the difference in water elevations will be less than 5 feet, DOE estimated that the pumping energy (lift) would be about 35 feet (energy factor of about 44 MWh/TAF); the additional pumping energy for Alternative 9 was estimated to be a constant 2 MW (18 GWh/yr).

21.3.2 Determination of Effects

The effects of the BDCP alternatives on energy consumption may result from both construction and operation of the BDCP features. Alternative 1A, which includes a tunnel conveyance from five north Delta intakes to the south Delta pumping plants, would require about 182 MW of power (capacity) to pump and transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the existing CVP and SWP pumps near Tracy through a tunnel conveyance. DWR has determined that the maximum pumping energy factor for the 15,000 cfs tunnel would be about 145 MWh/TAF. Pumping about 30 TAF/day would therefore require 4,350 MWh per day of energy, with a maximum power of 182 MW. The daily energy requirement would depend on the daily pumping volume.

The west alignment (Alternatives 1C, 2C, and 6C, which include several tunnel sections) would require about 132 MW of additional power (capacity) to pump a maximum flow of 15,000 cfs. DWR has determined that the pumping energy factor for the 15,000 cfs west alignment would be about 110 MWh/TAF. Pumping about 30 TAF/day would therefore require 3,300 MWh per day of energy, with a maximum power of 138 MW. The daily energy requirement would depend on the daily pumping volume.

The east alignment (Alternatives 1B, 2B, and 6B) would require about 82 MW of additional power (capacity) to pump a maximum flow of 15,000 cfs. DWR has determined that the pumping energy factor for the 15,000 cfs east alignment would be about 65 MWh/TAF. Pumping about 30 TAF/day would therefore require 1,950 MWh per day of energy, with a maximum power of 82 MW. The daily energy requirement would depend on the daily pumping volume.

The through Delta/separate corridors alignment (Alternative 9) would require about 2 MW of additional power (capacity) for circulation pumps (500 cfs capacity) in the south Delta. The SWP and CVP water supplies would be conveyed through the existing Delta channels as they are now conveyed (with tidal energy and gravity flow).

The amount of energy needed each year for an alternative would be proportional to the water pumped from the north Delta (times the energy factor assumed for each alternative) and the amount of water pumped from the south Delta (times the overall energy factor for the CVP and SWP deliveries). As described above, the overall energy factor for the CVP and the SWP is assumed to remain constant for all BDCP alternatives, so the overall energy use for pumping and delivery from the Delta would be proportional to the total Delta exports. The total energy use for an alternative will be calculated from the north Delta energy use added to the energy used for pumping and delivery of Delta exports to CVP and SWP contractors.

Total energy use for each BDCP alternative was compared to Existing Conditions and No Action Alternative to determine net energy use. At the south Delta, net energy use is directly related to the change in the total CVP and SWP Delta exports, and represents a greater utilization of the existing (2010) pumping facilities, rather than a new requirement for energy beyond the generating capacity of existing facilities. Because the existing CVP and SWP pumping facilities at the south delta have been planned and previously operated for a maximum monthly energy requirement that is greater than the energy requirement estimated for BDCP, increased use of the existing pumping facilities is not considered a new energy impact and is not discussed further.

Under State CEQA guidelines Appendix F, *Energy Conservation*, a project should consider the effects on the local and regional energy supplies and requirements for additional capacity. The review of these effects and the discussion of potential impacts should include particular emphasis on avoiding or reducing inefficient consumption of energy. Accordingly, for the purposes of this analysis, an adverse energy effect would occur if the project resulted in wasteful or unnecessary energy consumption during either construction or operation.

21.3.2.1 Potential for New Energy Resources

Power planning for loads within California is the responsibility of the CEC on a state-wide basis and the loads' Local Regulatory Authority (LRA) on a Load Serving Entity (LSE) basis. The CEC develops and adopts an Integrated Energy Policy Report (IEPR) every two years and an update every other year. Preparation of the IEPR involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues. The most recent report was completed in 2011 and was updated in 2012. BDCP facilities were not included in the studies for the 2011 IEPR or 2012 IEPR Update. However, with 270 MW as construction load and 57 MW as permanent load, the BDCP facilities would be approximately 0.40% and 0.09%, respectively, of the state's load. In addition, the BDCP construction load is less than one-half of the lower end of the annual growth rate for the state's load.

According to a final Order issued by the FERC on January 22, 2007, the SWP is considered a LSE for Resource Adequacy (RA) purposes. In response to an earlier Order from FERC, on August 31, 2006, DWR executive management signed documentation that established DWR as the LRA over the SWP. DWR most recent version of its RA Program, dated October 30, 2011, requires that the SWP comply with the CAISO Tariff Section 40.1 regarding RA requirements of an LSE within the CAISO's BA. Per the RA Program and CAISO Tariff, SWP submits demand forecasts to CEC and CAISO on a year-ahead and month-ahead basis. SWP also submits RA compliance demonstrations to the CAISO on a year-ahead and month-ahead basis. In addition, the RA Program includes a 15% Planning Reserve Margin on all firm load. Consequently, SWP will procure power and capacity for BDCP through long-term and mid-term contracts, and the CAISO power markets, sufficient to meet the power and RA capacity requirements of the CAISO Tariff and DWR's RA Program. The potential for new or expanded electrical power generation facilities is therefore not discussed in this section as it will be addressed through SWP power purchase programs.

21.3.3 Effects and Mitigation Approaches

A summary of average annual energy requirements for each BDCP alternative is provided in Table 21-11. The average annual north Delta intake pumping and associated energy requirements for each BDCP alternative are summarized for easy comparison. The average annual Delta export pumping and associated energy uses for CVP and SWP water deliveries are also included in Table 21-11. This allows the average annual net energy use for each BDCP alternative to be compared to Existing Conditions and the No Action Alternative.

The pumping energy factor for south of Delta CVP and SWP water deliveries are identical under Existing Conditions and No Action Alternative (1.5 GWh/TAF/year). Likewise, no new energy demand at the North Delta would be created under Existing Conditions or the No Action Alternative. Accordingly, the CEQA (Existing Conditions) and NEPA (No Action Alternative) baselines have different total energy uses that are proportional to the simulated CVP and SWP exports (TAF). However, each of the baselines use the same amount of energy for each TAF of water deliveries. In other words, energy intensity for water deliveries under the NEPA and CEQA baselines is identical (1.5 GWh/TAF/year).

1 **Table 21-11. Summary of Annual Average Pumping (TAF) and Net Energy Use (GWh) for BDCP Alternatives [a]**

							Relative to NEPA Point of Comparison		Relative to CEQA Baseline	
BDCP Alternative	Condition	North Delta Pumping (TAF/yr)	North Delta Energy (GWh)	Energy Factor (MWh/TAF)	Total Delta Pumping (TAF/yr)	South of Delta Energy (GWh)	Increased Energy Use (GWh)	Percent Increase (%)	Increased Energy Use (GWh)	Percent Increase (%)
Existing Conditions [b]	2010	0	0	0	5,144	7,716	-	-	-	-
No Action Alternative [c]	2060	0	0	0	4,441	6,662	-	-	-	-
Alternative 1A	2025	2,928	308	105	5,914	8,871	-	-	1,463	19%
Pipeline/Tunnel-Variable energy factor	2060	2,704	291	108	5,456	8,184	1,814	27%	759	10%
Alternative 1B	2025	2,928	190	65	5,914	8,871	-	-	1,345	17%
East Alignment-65 MWh/TAF	2060	2,704	176	65	5,456	8,184	1,699	25%	644	8%
Alternative 1C	2025	2,928	322	110	5,914	8,871	-	-	1,477	19%
West Alignment-110 MWh/TAF	2060	2,704	297	110	5,456	8,184	1,820	27%	765	10%
Alternative 2A	2025	3,080	341	111	5,389	8,084	-	-	709	9%
15,000 cfs Pipeline/Tunnel-Variable energy factor	2060	2,930	328	112	5,068	7,602	1,269	19%	214	3%
Alternative 2B	2025	3,080	200	65	5,389	8,084	-	-	568	7%
East Alignment-65 MWh/TAF	2060	2,930	190	65	5,068	7,602	1,131	17%	76	1%
Alternative 2C	2025	3,080	339	110	5,389	8,084	-	-	707	9%
West Alignment-110 MWh/TAF	2060	2,930	322	110	5,068	7,602	1,263	19%	208	3%
Alternative 3	2025	2,051	134	65	5,818	8,727	-	-	1,145	15%
6,000 cfs Pipeline/Tunnel-65 MWh/TAF	2060	1,864	122	65	5,371	8,057	1,517	23%	463	6%
Alternative 4 (Scenario H1)	2025	2,674	175	65	5,591	8,387	-	-	846	11%
65 MWh/TAF	2060	2,463	161	65	5,255	7,883	1,382	21%	328	4%
Alternative 4 (Scenario H2)	2025	2,353	153	65	5,005	7,508	-	-	-56	-1%
65 MWh/TAF	2060	2,149	141	65	4,710	7,065	545	8%	-510	-7%
Alternative 4 (Scenario H3)	2025	2,603	170	65	5,265	7,898	-	-	352	5%
65 MWh/TAF	2060	2,435	157	65	4,945	7,418	913	14%	-142	-2%

BDCP Alternative	Condition	North Delta Pumping (TAF/yr)	North Delta Energy (GWh)	Energy Factor (MWh/TAF)	Total Delta Pumping (TAF/yr)	South of Delta Energy (GWh)	Relative to NEPA Point of Comparison: Increased Energy Use (GWh)	Relative to NEPA Point of Comparison: Percent Increase (%)	Relative to CEQA Baseline: Increased Energy Use (GWh)	Relative to CEQA Baseline: Percent Increase (%)
Alternative 4 (Scenario H4)	2025	2,288	150	65	4,705	7,898	-	-	-509	-7%
Large Diameter Pipeline/Tunnel-65 MWh/taf	2060	2,144	140	65	4,414	7,418	100	1%	-955	-12%
Alternative 5	2025	1,278	84	65	5,183	7,775	-	-	143	2%
3,000 cfs Pipeline/Tunnel-65 MWh/TAF	2060	1,191	78	65	4,786	7,179	596	9%	-459	-6%
Alternative 6A	2025	4,031	466	115	4,031	6,047	-	-	-1,204	-16%
15,000 cfs Pipeline/Tunnel-Variable energy factor	2060	3,758	421	112	3,759	5,639	-602	-9%	-1,657	-21%
Alternative 6B	2025	4,031	262	65	4,031	6,047	-	-	-1,408	-18%
East Alignment-65 MWh/TAF	2060	3,758	244	65	3,759	5,639	-779	-12%	-1,834	-24%
Alternative 6C	2025	4,031	443	110	4,031	6,047	-	-	-1,227	-16%
West Alignment-110 MWh/TAF	2060	3,758	413	110	3,759	5,639	-610	-9%	-1,665	-22%
Alternative 7	2025	2,502	207	83	3,989	5,984	-	-	-1,526	-20%
9,000 cfs Pipeline/Tunnel-Variable energy factor	2060	2,338	193	83	3,754	5,631	-838	-13%	-1,892	-25%
Alternative 8	2025	2,326	199	86	3,312	4,968	-	-	-2,549	-33%
9,000 cfs Pipeline/Tunnel-Variable energy factor	2060	2,182	185	85	3,098	4,647	-1,830	-27%	-2,884	-37%
Alternative 9	2025	0	18	0	4,629	6,944	-	-	-755	-10%
Through Delta/Separate Corridors	2060	0	18	0	4,377	6,566	-78	-1%	-1,133	-15%

- Not used for energy comparison

[a] Energy calculations based on CALSIM-II represent a reasonable, though overstated, scenario based on historic monthly flows and reservoir storage.

[b] Installed SWP and CVP capacity in 2010.

[c] Future SWP and CVP capacity in 2060 independent of BDCP actions.

In the event that Delta water deliveries could not meet south of Delta water supply, alternative water sources for south of the Delta service areas could be accessed to supplement deliveries. New south of Delta surface water storage, groundwater pumping, and desalination plants could provide some of the necessary supplies and would create additional energy demands. While it is important to acknowledge this possibility, it is difficult to quantify and analyze the variety of supplemental water sources in a meaningful way. The uncertainty around additional water supplies would need to be addressed and analyzed on a case by case basis as they become feasible alternatives.

21.3.3.1 No Action Alternative

The No Action Alternative assumes continued energy generation and use at CVP and SWP facilities similar to those for recent operations (Existing Conditions) in the year 2060. Slight variances would be expected from the potential reoperation of reservoirs and energy generation facilities to accommodate changes in future precipitation and snowmelt runoff patterns and increased release flows in some months to improve habitat conditions in the rivers and tidal sloughs of the Plan Area. Additionally, RPMs under the 2008 and 2009 NMFS and USFWS Biological Opinions would potentially require changes to South Delta pumping.

The CALSIM-II simulation of No Action Alternative (2060) upstream reservoir operations and river flows was used to estimate the No Action energy generation at the upstream CVP and SWP facilities. The energy use for south of Delta pumping and delivery of water to CVP and SWP contractors was estimated from the CALSIM-II simulations of CVP and SWP pumping and deliveries for 1922–2003.

Tables 21-12a through 21-12f show the monthly and annual summary of CVP and SWP upstream energy generation and use for pumping and delivery to CVP and SWP contractors for the No Action Alternative. These tables were estimated from the monthly and annual pumping volumes (TAF) at each CVP and SWP pumping plant and the assumed pumping energy factors (MWh/TAF). For evaluation purposes, the average annual energy factor for SWP deliveries and the annual average energy factor for CVP deliveries were calculated and used to compare the energy needed for Delta exports.

Table 21-12a shows the monthly and annual cumulative distributions of CVP upstream energy generation (GWh) for the No Action Alternative. The average annual upstream CVP energy generation was 4,789 GWh for the No Action Alternative.

Table 21-12a. Monthly and Annual Cumulative Distributions of Estimated Upstream CVP Energy Generation (GWh) for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	89	79	86	90	90	105	154	225	293	346	278	132	2,528
10%	196	134	120	139	123	143	239	293	384	523	405	224	3,111
20%	230	159	140	154	143	168	260	363	459	566	468	269	3,541
30%	239	183	152	161	152	186	292	408	474	602	506	308	3,889
40%	268	201	176	180	186	217	305	435	502	640	522	321	4,168
50%	286	225	184	209	199	241	325	458	528	663	543	364	4,682
60%	309	260	200	261	258	269	345	482	553	686	560	417	5,143
70%	333	285	246	367	386	375	378	508	565	712	574	536	5,407
80%	404	346	337	489	647	609	420	583	583	728	589	603	6,101
90%	451	411	662	714	700	760	565	692	604	755	645	656	6,647
Maximum	530	779	945	1,077	860	1,060	828	830	1,036	1,052	789	755	9,536
Average	302	256	270	322	329	349	360	475	523	652	536	416	4,789

Table 21-12b shows the monthly and annual cumulative distributions of CVP Jones pumping (TAF) for the No Action Alternative.

Table 21-12b. Monthly and Annual Cumulative Distributions of CALSIM-II-Simulated CVP Delta Pumping (TAF) for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	81	81	90	46	36	35	36	49	36	39	37	48	984
10%	149	131	181	122	70	57	48	49	48	129	130	146	1,525
20%	176	165	222	144	114	116	48	49	57	218	216	166	1,929
30%	190	198	239	165	130	138	48	49	92	247	283	207	2,126
40%	200	229	247	189	157	146	48	49	102	279	283	242	2,189
50%	216	243	262	200	175	162	51	49	138	280	283	273	2,301
60%	237	274	283	208	187	188	54	49	153	283	283	274	2,364
70%	257	274	283	211	205	216	58	55	168	283	292	274	2,458
80%	279	274	283	236	220	256	67	69	205	283	321	274	2,619
90%	283	340	283	272	255	283	96	103	274	283	330	281	2,769
Maximum	283	399	283	283	265	283	162	267	274	380	343	336	3,007
Average	218	236	249	192	166	171	62	68	140	244	260	233	2,237

Table 21-12c shows the monthly and annual cumulative distributions of CVP energy use (GWh) for CVP water pumping at Jones and all other pumping plants along the Delta-Mendota Canal, including pumping at O'Neill and Gianelli pumping plants to store water in San Luis Reservoir. The energy generation at these generating plants was subtracted from the monthly CVP energy use values. The average net energy factor for CVP exports was about 363 MWh/TAF, based on the average No Action Alternative CVP Jones pumping of 2,237 TAF/yr and the average net CVP energy use of 814 GWh/yr.

Table 21-12c. Monthly and Annual Cumulative Distributions of Estimated CVP Net Energy Use (GWh) for Delta Export Pumping and Delivery for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	12	28	41	21	11	-1	-17	-31	-25	-16	-16	-25	277
10%	46	52	92	60	29	13	-12	-20	-14	21	25	34	495
20%	55	68	113	74	47	44	-8	-16	-4	55	60	53	695
30%	63	83	122	84	61	51	-5	-11	2	67	72	64	744
40%	68	101	128	96	73	55	-3	-9	5	73	79	81	774
50%	75	113	135	103	83	67	-1	-7	14	75	82	93	828
60%	83	125	142	107	89	85	3	-4	27	80	87	94	856
70%	92	132	144	112	102	97	7	-2	33	82	91	95	920
80%	102	135	146	125	116	125	12	4	58	85	103	96	979
90%	108	157	150	147	129	138	32	22	89	87	107	106	1,075
Maximum	147	186	161	169	150	157	66	112	99	127	111	126	1,275
Average	77	107	128	100	80	75	5	-1	25	67	75	77	814

Table 21-12d shows the monthly and annual cumulative distributions of SWP upstream energy generation (GWh) for the No Action Alternative. The average annual upstream SWP energy generation was 2,292 GWh for the No Action Alternative.

Table 21-12d. Monthly and Annual Cumulative Distributions of Estimated Upstream SWP Energy Generation (GWh) for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	26	20	21	19	20	19	47	54	109	40	40	33	721
10%	36	25	26	23	31	24	72	103	141	219	80	56	1,183
20%	41	33	42	28	40	39	92	118	155	295	143	75	1,447
30%	68	49	54	46	50	58	97	125	173	354	194	116	1,559
40%	89	55	56	55	54	73	105	127	190	395	261	148	1,815
50%	114	70	59	58	57	138	116	133	212	415	273	160	1,985
60%	131	82	92	59	103	201	126	139	234	424	300	255	2,470
70%	142	85	121	67	212	248	153	193	250	451	310	320	2,880
80%	156	89	156	199	379	357	226	329	271	471	325	376	3,337
90%	169	94	229	540	563	549	358	481	350	490	336	416	3,581
Maximum	223	561	670	669	623	671	666	698	569	508	377	441	4,777
Average	107	75	119	148	182	203	170	216	232	380	244	217	2,292

Table 21-12e shows the monthly and annual cumulative distributions of SWP Banks pumping (TAF) for the No Action Alternative.

Table 21-12e. Monthly and Annual Cumulative Distributions of CALSIM-II-Simulated SWP Delta Export Pumping (TAF) for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	59	18	81	18	21	18	18	18	18	18	18	55	896
10%	107	18	172	134	105	81	42	43	38	333	24	125	1,723
20%	136	18	228	151	138	140	42	43	58	375	295	202	2,154
30%	154	63	242	177	168	154	42	43	84	400	338	239	2,277
40%	167	107	257	189	185	179	48	43	95	408	347	268	2,424
50%	182	140	276	202	198	215	51	44	113	411	358	277	2,588
60%	197	172	348	208	217	248	55	50	150	411	393	296	2,811
70%	219	228	378	216	269	288	63	56	167	411	411	363	3,006
80%	253	319	431	241	328	376	71	69	223	411	411	394	3,272
90%	297	397	435	338	406	446	96	103	303	411	411	397	3,477
Maximum	411	397	472	523	472	465	364	380	397	411	411	397	4,433
Average	196	166	306	217	229	237	63	68	146	381	324	279	2,614

Table 21-12f shows the monthly and annual cumulative distributions of SWP net energy use for SWP water pumping (GWh) at Banks and all other pumping plants along the California Aqueduct. The energy generation at the SWP generating plants on the west and east branches of the aqueduct in southern California (which recovers a fraction of the energy required to pump the water over the Tehachapi Mountains) is subtracted from the monthly energy use values. The average net energy factor for SWP exports was about 2,420 MWh/TAF, based on the average No Action Alternative SWP Banks pumping of 2,614 TAF/yr and the average net SWP energy use of 6,327 GWh/yr.

Table 21-12f. Monthly and Annual Cumulative Distributions of Estimated SWP Net Energy Use (GWh) for Delta Export Pumping and Delivery for the No Action Alternative

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Minimum	124	77	113	46	88	120	151	53	42	272	32	155	2,290
10%	216	183	258	140	165	217	293	374	264	521	383	332	4,283
20%	396	344	350	154	215	294	417	461	317	671	654	552	5,145
30%	438	400	392	186	285	355	425	482	471	683	676	586	5,693
40%	459	441	464	217	389	408	438	496	507	699	693	618	6,115
50%	517	469	503	347	485	502	481	508	536	723	719	657	6,564
60%	544	483	535	431	592	658	503	538	562	746	737	671	6,955
70%	564	503	597	508	704	721	523	562	592	760	752	687	7,231
80%	603	532	626	716	751	813	547	576	637	788	780	710	7,638
90%	678	602	712	765	801	891	592	668	734	851	831	759	8,038
Maximum	903	782	896	933	888	960	837	881	853	890	891	858	9,930
Average	492	441	491	399	489	538	470	516	503	704	673	611	6,327

The average energy factor for combined CVP and SWP south of Delta pumping can be estimated as the flow weighted average of the CVP and SWP energy factors. The average CVP pumping was 2,237 TAF/yr with an energy factor of 363 MWh/TAF. The average SWP pumping was 2,614 TAF/yr with an energy factor of 2,420 MWh/TAF. The combined energy factor would be about 1.5 GWh/TAF. Accordingly, the No Action Alternative would not increase the energy use factor (1.5 GWh/TAF) and would not result in an adverse effect on energy resources.

Climate Change and Catastrophic Seismic Risks

The Delta and vicinity are within a highly active seismic area, with a generally high potential for major future earthquake events along nearby and/or regional faults, and with the probability for such events increasing over time. Based on the location, extent and non-engineered nature of many existing levee structures in the Delta area, the potential for significant damage to, or failure of, these structures during a major local seismic event is generally moderate to high. In the instance of a large seismic event, levees constructed on liquefiable foundations are expected to experience large deformations (in excess of 10 feet) under a moderate to large earthquake in the region. While there are no set thresholds for salinity, bromide, or other contaminants at which the Banks and/or Jones Pumping Plants would cease operations, an event that would alter the hydrology of the Delta such that brackish water or seawater is drawn into the southwest portion of the Delta would likely result in these pumps shutting down until freshwater flows can be reestablished and flush the brackish water/seawater from the vicinity of these pumping plants' intakes. (See Appendix 3E, *Potential Seismic and Climate Change Risks to SWP/CVP Water Supplies* for more detailed discussion) Depending on the duration of the interruption, this could result in a substantial decrease in energy use at the SWP and CVP Delta pumping plants. This decrease in energy use could be offset if south of Delta water uses switch to alternative water supplies. To reclaim land or rebuild levees after a catastrophic event due to climate change or a seismic event would create an increase in energy use during construction.

CEQA Conclusion: The energy use factor (1.5 GWh/TAF) under the No Action Alternative and Existing Conditions would be identical. Because the No Action Alternative would not increase the energy use factor, it would not result in a significant impact on energy resources.

21.3.3.2 Alternative 1A—Dual Conveyance with Pipeline/Tunnel and Intakes 1–5 (15,000 cfs; Operational Scenario A)

Alternative 1A includes a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 182 MW for pumping (and associated equipment) to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The maximum north Delta intakes and conveyance maximum energy factor for Alternative 1A is 145 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,426 GWh. That is an average of 158 GWh/year, with a peak use of 376 GWh occurring in year 6, concurrent with expected tunnel boring activity. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.2, construction of the water conveyance facilities associated with Alternative 1A includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion: Energy requirements for construction of the water conveyance facilities associated with Alternative 1A equate to 1,426 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.2, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 1A would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: The average north Delta intake pumping would be 2,928 TAF/yr under 2025 conditions and 2,704 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping was estimated to be 308 GWh/yr under 2025 conditions and 291 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1A would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 1A would require an additional 308 GWh/yr under 2025 conditions and 291 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1A would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: Constructing the proposed water conveyance facilities (CM1) and implementing CM2–CM22 could result in the potential for incompatibilities with plans and policies related to energy resources. A number of plans and policies that coincide with the study area provide guidance for energy resource issues as overviewed in *Section 21.2, Regulatory Setting*. This overview of plan and policy compatibility evaluates whether Alternative 1A is compatible or incompatible with such enactments, rather than whether impacts are adverse or not adverse or significant or less than significant. If the incompatibility relates to an applicable plan, policy, or regulation adopted to avoid or mitigate energy effects, then an incompatibility might be indicative of a related significant or adverse effect under CEQA and NEPA, respectively. Such physical effects of Alternative 1A on energy resources are addressed in Impacts ENG-1 and ENG-2. The following is a summary of compatibility evaluations related to energy resources for plans and policies relevant to the BDCP. Note that as discussed in Chapter 13, *Land Use,* Section 13.2.3, state and federal agencies are not generally subject to local land use regulations; incompatibilities with plans and policies are not, by themselves, physical consequences to the environment.

- The BDCP alternative would be constructed and operated in compliance with regulations related to energy resources enforced by FERC and other federal agencies. The alternative would not interfere or obstruct FERC Order No. 888 and Order No. 889, or CAISO Tariff Section 40.1. Compatibility with other federal acts, including the Rivers and Harbors Appropriation Act of 1899, Section 10; the Rivers and Harbors Act of 1935; the Rivers and Harbors Act of 1937; the Rivers and Harbors Act of 1940; the Auburn-Folsom South Unit Authorization Agreement; the Emergency Relief Appropriation Act of 1935; the Flood Control Act of 1944; the Federal Endangered Species Act; and the Central Valley Project Improvement Act (CVPIA) Section 3406 (b)(2) is discussed in Chapter 5, *Water Supply*; Chapter 11, *Fish and Aquatic Resources*; and Chapter 12, *Terrestrial Biological Resources*.

- The BDCP alternative will not conflict with the Warren-Alquist Act, which promotes energy efficiency throughout the state.
- The BDCP alternative is consistent with CEQA Guidelines, Appendix F, *Energy Conservation*.

CEQA Conclusion: Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.3 Alternative 1B—Dual Conveyance with East Alignment and Intakes 1–5 (15,000 cfs; Operational Scenario A)

Alternative 1B would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the east alignment canal. The maximum power requirements to operate the alternative would be about 82 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 1B is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 406 GWh. This is an average of 45 GWh/year, with a peak use of 83 GWh occurring in year 4. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.3, construction of the water conveyance facilities associated with Alternative 1B includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion: Energy requirements for construction of the water conveyance facilities associated with Alternative 1B equate to 406 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.3, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 1B would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 1B, the average north Delta intake pumping would be 2,928 TAF/yr under 2025 conditions and 2,704 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and east alignment conveyance was estimated to be 190 GWh/yr under 2025 conditions and 176 GWh/yr under 2060 conditions, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1B would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 1B would require an additional 190 GWh/yr under 2025 conditions and 176 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1B would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 1B would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.4 Alternative 1C—Dual Conveyance with West Alignment and Intakes W1–W5 (15,000 cfs; Operational Scenario A)

Alternative 1C would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the west alignment canal. The maximum power requirements to operate the alternative would be about 138 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 1C is 110 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 791 GWh. That is an average of 88 GWh/year, with a peak use of 196 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases,* Section 22.3.3.4, construction of the water conveyance facilities associated with Alternative 1C includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 1C equate to 791 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.4, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 1C would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 1C, the average north Delta intake pumping would be 2,928 TAF/yr under 2025 conditions and 2,704 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and west alignment conveyance was estimated to be 322 GWh/yr under 2025 conditions and 297 GWh/yr under 2060 conditions, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1C would not result in a wasteful or inefficient energy use. There would be no adverse effect. No mitigation is required.

***CEQA Conclusion*:** Operation of Alternative 1C would require an additional 322 GWh/yr under 2025 conditions and 297 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 1C would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 1C would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.5 Alternative 2A—Dual Conveyance with Pipeline/Tunnel and Five Intakes (15,000 cfs; Operational Scenario B)

Alternative 2A would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 182 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The maximum north Delta intakes and conveyance energy factor for Alternative 2A is 145 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,426 GWh. That is an average of 158 GWh/year, with a peak use of 376 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.5, construction of the water conveyance facilities associated with Alternative 2A includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion**:** Energy requirements for construction of the water conveyance facilities associated with Alternative 2A equate to 1,426 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.5, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 2A would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 2A, the average north Delta intake pumping would be 3,080 TAF/yr under 2025 conditions and 2,930 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance was estimated to be 341 GWh/yr under 2025 conditions and 328 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2A would not result in a wasteful or inefficient energy use. There would be no adverse effect.

CEQA Conclusion**:** Operation of Alternative 2A would require an additional 524 GWh/yr under 2025 conditions and 498 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2A would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 2A would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion**:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.6 Alternative 2B—Dual Conveyance with East Alignment and Five Intakes (15,000 cfs; Operational Scenario B)

Alternative 2B would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the east alignment. The maximum power requirements to operate the alternative would be about 82 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 2B is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 406 GWh. This is an average of 45 GWh/year, with a peak use of 83 GWh occurring in year 4. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.6, construction of the water conveyance facilities associated with Alternative 2B includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 2B equate to 406 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.6, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 2B would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 2B, the average north Delta intake pumping would be 3,080 TAF/yr under 2025 conditions and 2,930 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and east alignment conveyance was estimated to be 200 GWh/yr under 2025 conditions and 190 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2B would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 2B would require an additional 200 GWh/yr under 2025 conditions and 190 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2B would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 2B would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion: Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.7 Alternative 2C—Dual Conveyance with West Alignment and Intakes W1–W5 (15,000 cfs; Operational Scenario B)

Alternative 2C would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the west alignment. The maximum power requirements to operate the alternative would be about 138 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 2C is 110 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 790 GWh. This is an average of 88 GWh/year, with a peak use of 196 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.7, construction of the water conveyance facilities associated with Alternative 2C includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion: Energy requirements for construction of the water conveyance facilities associated with Alternative 2C equate to 790 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.7, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 2C would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 2C, the average north Delta intake pumping would be 3,080 TAF/yr under 2025 conditions and 2,930 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and west alignment conveyance was estimated to be 339 GWh/yr under 2025 conditions and 322 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2C would not result in a wasteful or inefficient energy use. There would be no adverse effect.

CEQA Conclusion: Operation of Alternative 2C would require an additional 339 GWh/yr under 2025 conditions and 322 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 2C would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 2C would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.8 Alternative 3—Dual Conveyance with Pipeline/Tunnel and Intakes 1 and 2 (6,000 cfs; Operational Scenario A)

Alternative 3 would require energy transmission and use for a pumping capacity of 6,000 cfs at north Delta intakes and conveyance through the proposed tunnel. The maximum power requirements to operate the alternative would be about 33 MW for pumping to transport a maximum flow of 6,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 3 is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,320 GWh. This is an average of 147 GWh/year, with a peak use of 361 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.8, construction of the water conveyance facilities associated with Alternative 3 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 3 equate to 1,320 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.8, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 3 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 3, the average north Delta intake pumping would be 2,051 TAF/yr under 2025 conditions and 1,864 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance was estimated to be 134 GWh/yr under 2025 conditions and 122 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 3 would not result in a wasteful or inefficient energy use. There would be no adverse effect.

CEQA Conclusion: Operation of Alternative 3 would require an additional 134 GWh/yr under 2025 conditions and 122 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 3 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 3 would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion: Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3

21.3.3.9 Alternative 4—Dual Conveyance with Modified Pipeline/Tunnel and Intakes 2, 3, and 5 (9,000 cfs; Operational Scenario H)

Alternative 4 would require energy transmission and use for a pumping capacity of 9,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 50 MW for pumping to transport a maximum flow of 9,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 4 is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 2,549 GWh. This is an average of 283 GWh/year, with a peak use of 483 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.9, construction of the water conveyance facilities associated with Alternative 4 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion: Energy requirements for construction of the water conveyance facilities associated with Alternative 4 would equate to 2,549 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.9, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 4 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 4, the average north Delta intake pumping under Scenario H1 would be 2,674 TAF/yr under 2025 conditions and 2,463 TAF/yr under 2060 conditions. Under Scenario H4, average north Delta intake pumping would be 2,2883 TAF/yr under 2025 conditions and 2,144 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance was estimated to be 161 GWh/yr (2060 conditions) and 140 GWh/yr (2060 conditions) for Scenarios H1 and H4, respectively. These two scenarios reflect the range of effects that would result from the four potential outcomes under Alternative 4. While all scenarios would increase energy demand at the north delta, relative to the No Action Alternative, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 4 would not result in a wasteful or inefficient energy use. There would be no adverse effect.

CEQA Conclusion**:** Operation of Alternative 4 under Scenario H1 would require an additional 175 GWh/yr under 2025 conditions and 161 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. Operation of Alternative 4 under Scenario H4 would require an additional 150 GWh/yr under 2025 conditions and 140 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 4 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 4 would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion**:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3

21.3.3.10 Alternative 5—Dual Conveyance with Pipeline/Tunnel and Intake 1 (3,000 cfs; Operational Scenario C)

Alternative 5 would require energy transmission and use for a pumping capacity of 3,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 16 MW for pumping to transport a maximum flow of 3,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 5 is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 731 GWh. This is an average of 81 GWh/year, with a peak use of 197 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.10, construction of the water conveyance facilities associated with Alternative 5 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 5 equate to 731 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.10, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 5 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 5, the average north Delta intake pumping would be 1,278 TAF/yr under 2025 conditions and 1,191 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance for Alternative 5 is estimated to be 84 GWh/yr under 2025 conditions and 78 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 5 would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 5 would require an additional 84 GWh/yr under 2025 conditions and 78 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 5 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 5 would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3

21.3.3.11 Alternative 6A—Isolated Conveyance with Pipeline/Tunnel and Intakes 1-5 (15,000 cfs; Operational Scenario D)

Alternative 6A would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 182 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The maximum north Delta intakes and conveyance energy factor for Alternative 6A is 145 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,426 GWh. This is an average of 158 GWh/year, with a peak use of 376 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.11, construction of the water conveyance facilities associated with Alternative 6A includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 6A equate to 1,426 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.11, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 6A would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 6A, the average north Delta intake pumping would be 4,031 TAF/yr under 2025 conditions and 3,758 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance was estimated to be 466 GWh/yr under 2025 conditions and 421 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6A would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 6A would require additional energy for north Delta pumping of 466 GWh/yr under 2025 conditions and 421 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6A would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 6A would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG -2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.12 Alternative 6B—Isolated Conveyance with East Alignment and Intakes 1–5 (15,000 cfs; Operational Scenario D)

Alternative 6B would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the east alignment. The maximum power requirements to operate the alternative would be about 820 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 6B is 65 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 406 GWh. This is an average of 45 GWh/year, with a peak use of 83 GWh occurring in year 4. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.12, construction of the water conveyance facilities associated with Alternative 6B includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 6B equate to 406 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.12, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 6B would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 6B, the average north Delta intake pumping would be 4,031 TAF/yr under 2025 conditions and 3,758 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and east alignment conveyance was estimated to be 262 GWh/yr under 2025 conditions and 244 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6B would not result in a wasteful or inefficient energy use. There would be no adverse effect.

CEQA Conclusion**:** Operation of Alternative 6B would require an additional 262 GWh/yr under 2025 conditions and 244 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6B would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 6B would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion**:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.13 Alternative 6C—Isolated Conveyance with West Alignment and Intakes W1–W5 (15,000 cfs; Operational Scenario D)

Alternative 6C would require energy transmission and use for a pumping capacity of 15,000 cfs at north Delta intakes and conveyance through the west alignment. The maximum power requirements to operate the alternative would be about 138 MW for pumping to transport a maximum flow of 15,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The north Delta intakes and conveyance energy factor for Alternative 6C is 110 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 790 GWh. This is an average of 88 GWh/year, with a peak use of 196 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.13, construction of the water conveyance facilities associated with Alternative 6C includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

CEQA Conclusion**:** Energy requirements for construction of the water conveyance facilities associated with Alternative 6C equate to 790 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.13, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 6C would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 6C, the average north Delta intake pumping would be 4,031 TAF/yr under 2025 conditions and 3,758 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and west alignment conveyance was estimated to be 443 GWh/yr under 2025 conditions and 413 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6C would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 6C require additional energy for north Delta pumping of 443 GWh/yr under 2025 conditions and 413 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 6C would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 6C would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3

21.3.3.14 Alternative 7—Dual Conveyance with Pipeline/Tunnel, Intakes 2, 3, and 5, and Enhanced Aquatic Conservation (9,000 cfs; Operational Scenario E)

Alternative 7 would require energy transmission and use for a pumping capacity of 9,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 80 MW for pumping to transport a maximum flow of 9,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The maximum north Delta intakes and conveyance energy factor for Alternative 7 is 105 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,355 GWh. This is an average of 151 GWh/year, with a peak use of 366 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.14, construction of the water conveyance facilities associated with Alternative 7 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 7 equate to 1,355 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.14, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 7 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 7, the average north Delta intake pumping was 2,502 TAF/yr under 2025 conditions and 2,338 TAF/yr under 2060 conditions. The energy use for north Delta intake pumping and tunnel conveyance was estimated to be 207 GWh/yr under 2025 conditions and 193 GWh/yr for LLT, which is greater than the No Action Alternative (requires no pumping at the North Delta). However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 7 would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 7 would require additional energy for north Delta pumping of 207 GWh/yr under 2025 conditions and 193 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 7 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 7 would be compatible with applicable plans and policies related to energy sources.

CEQA Conclusion: Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.15 Alternative 8—Dual Conveyance with Pipeline/Tunnel, Intakes 2, 3, and 5, and Increased Delta Outflow (9,000 cfs; Operational Scenario F)

Alternative 8 would require energy transmission and use for a pumping capacity of 9,000 cfs at north Delta intakes and conveyance through the tunnel. The maximum power requirements to operate the alternative would be about 80 MW for pumping to transport a maximum flow of 9,000 cfs from the Sacramento River near Hood to the SWP Clifton Court Forebay near Tracy. The maximum north Delta intakes and conveyance energy factor for Alternative 8 is 105 MWh/TAF.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 9-year construction period would be about 1,355 GWh. This is an average of 151 GWh/year, with a peak use of 366 GWh occurring in year 6. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.15, construction of the water conveyance facilities associated with Alternative 8 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 8 equate to 1,355 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.15, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 8 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: As shown in Table 21-11 for Alternative 8, the average north Delta intake pumping was 2,326 TAF/yr under 2025 conditions and 2,182 TAF/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 8 would not result in a wasteful or inefficient energy use. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 8 would require an additional 199 GWh/yr under 2025 conditions and 185 GWh/yr under 2060 conditions for north Delta pumping, relative to Existing Conditions. However, operation of the water conveyance facility would be managed to maximize efficient energy use, including off-peak pumping and use of gravity. Accordingly, implementation of Alternative 8 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 8 would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.16 Alternative 9—Through Delta/Separate Corridors (15,000 cfs; Operational Scenario G)

This alternative would require very small additional energy use for south Delta circulation pumps with a total capacity of 500 cfs. These circulation pumps would be used continuously. DWR has estimated the electrical energy requirements for construction to be about one-half of the east alignment construction energy. This estimate may be high relative to the size of the pumping stations and other facilities required to construct the San Joaquin River separate corridor along Old River, the fish screens at Delta Cross Channel and Georgiana Slough, and the tidal gates at Threemile Slough. DWR has estimated the two pumping plants would require an electrical capacity of 2 MW. The additional annual energy use would therefore be about 18 GWh.

Impact ENG-1: Wasteful or Inefficient Energy Use for Temporary Construction Activities

NEPA Effects: Table 21-9 indicates that the total construction energy use estimate for the 7-year construction period would be about 186 GWh. This is an average of 27 GWh/year, with a peak use of 42 GWh occurring in year 4. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.16, construction of the water conveyance facilities associated with Alternative 9 includes all feasible control measures to improve equipment efficiency and energy use. Although energy will be consumed as a result of construction activities, BMPs will ensure that only high-efficiency equipment is utilized during construction. Construction activities would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, there would be no adverse effect.

***CEQA Conclusion*:** Energy requirements for construction of the water conveyance facilities associated with Alternative 9 equate to 186 GWh over the 9-year construction period. As discussed in Chapter 22, *Air Quality and Greenhouse Gases*, Section 22.3.3.16, construction activities include all feasible control measures to improve equipment efficiency and energy use. Construction of the water conveyance facilities associated with Alternative 9 would therefore not result in the wasteful, inefficient or unnecessary consumption of energy. Accordingly, this impact would be less than significant and no mitigation is required.

Impact ENG-2: Wasteful or Inefficient Energy Use for Pumping and Conveyance

NEPA Effects: The CALSIM-II simulated total exports for Alternative 9 were 4,629 TAF/yr under 2025 conditions and 4,377 TAF/yr under 2060 conditions. Table 21-11 shows that Alternative 9 annual energy use for circulation pumping would be about 18 GWh/yr. This small increase in energy use, relative to the No Action Alternative (2060), would be managed to maximize efficient energy use. Accordingly, implementation of Alternative 9 would not result in a wasteful or inefficient energy use. There would be no adverse effect.

***CEQA Conclusion*:** Operation of Alternative 9 would require an additional 18 GWh/yr under 2025 and 2060 conditions for circulation pumping in the south Delta. This small increase in energy use, relative to Existing Conditions, would be managed to maximize efficient energy use. Accordingly, implementation of Alternative 9 would not result in a wasteful or inefficient energy use. Accordingly, this impact would be less than significant. No mitigation is required.

Impact ENG-3: Compatibility of the Proposed Water Conveyance Facilities and CM2–CM22 with Plans and Policies

NEPA Effects: The potential for inconsistencies with plans or polices would be similar to the discussion in Alternative 1A, Impact ENG-3. Construction and implementation of Alternative 9 would be compatible with applicable plans and policies related to energy sources.

***CEQA Conclusion*:** Physical effects associated with implementation of the alternative are discussed in impacts ENG-1 and ENG-2, above and no additional CEQA conclusion is required related to the consistency of the alternative with relevant plans and polices. The relationship between plans, policies, and regulations and impacts on the physical environment is discussed in Chapter 13, *Land Use,* Section 13.2.3.

21.3.3.17 Cumulative Analysis

This cumulative analysis considers other past, present and reasonably foreseeable future projects that could affect the same resources during the same timeframe as the BDCP, resulting in a cumulative energy effect. Energy use and local communities' demands for energy are expected to increase as a result of reasonably foreseeable future projects related to population growth and energy uses. It is expected that some changes related to energy use will take place although it is assumed that all future projects would include design and construction practices to avoid or minimize potential energy effects.

Cumulative effects of the BDCP alternatives on electrical energy generation and use within the three regions of the BDCP are expected to change as a result of past, present, and reasonably foreseeable future projects related to population growth and changes in economic activity in the three regions (see Chapter 30, *Growth Inducement and Other Indirect Effects,* Section 30.3.2).

When the effects of the BDCP alternatives on increased energy use are considered in connection with the potential effects of projects listed in Appendix 3D, *Defining Existing Conditions, the No Action/No Project, and Cumulative Impacts Conditions*, the cumulative effects on energy use are adverse because many of the other projects would also increase energy use in the three BDCP regions. The specific programs, projects, and policies are identified below, based on the potential to contribute to a BDCP energy impact that would be cumulatively considerable. The potential for cumulative impacts on energy generation and use are described for BDCP operational effects on energy use within the Delta and energy use in the South of Delta region of CVP and SWP water deliveries related to CM1.

Table 21-13 summarizes foreseeable projects and programs that may affect energy resources. Only those projects included in the cumulative analysis are listed.

1 **Table 21-13. Summary of Foreseeable Projects and Programs that May Affect Energy Resources**

Agency	Program/ Project	Description of Program/Project	Energy Effect
DWR	Oroville Facilities Relicensing	The objective of the relicensing process was to continue operation and maintenance of the Oroville Facilities for electric power generation, along with implementation of any terms and conditions to be considered for inclusion in a new FERC hydroelectric license	May reduce energy generation or require additional energy
Freeport Regional Water Authority and U.S. Bureau of Reclamation	Freeport Regional Water Project	Construction of a new water intake facility/pumping plant and 17-mile underground water pipeline within Sacramento County.	Increased energy demand
Davis, Woodland, and University of California, Davis	Davis-Woodland Water Supply Project	Divert up to about 46,100 acre-feet per year of surface water from the Sacramento River and convey it for treatment and subsequent use in Davis and Woodland and on the University of California, Davis campus	May reduce energy generation or require additional energy
Contra Costa Water District, U.S. Bureau of Reclamation, and California Department of Water Resources	Contra Costa Water District Alternate Intake Project	Locate a new drinking water intake at Victoria Canal, about 2.5 miles east of Contra Costa Water District's (CCWD) existing intake on the Old River, which would allow CCWD to divert higher quality water when it is available	Increased energy demand
Contra Costa Water District and U.S. Bureau of Reclamation	Los Vaqueros Reservoir Expansion Project	Increase the reservoir capacity to 275,000 acre-feet and add a new 470 cfs connection that would allow the Los Vaqueros system to provide water to South Bay water agencies – Alameda County Flood Control and Water Conservation District, Zone 7, Alameda County Water District, and Santa Clara Valley Water District – that otherwise would receive all of their Delta supplies through the existing SWP and CVP export pumps	Increased energy demand
U.S. Bureau of Reclamation and California State Water Resources Control Board	Battle Creek Salmon and Steelhead Restoration Project	Restoration of Battle Creek will be accomplished primarily through the modification of the Battle Creek Hydroelectric Project (Federal Energy Regulatory Commission [FERC] Project No. 1121) facilities and operations, including instream flow releases. Facility changes include the removal of five diversion dams and construction of fish ladders and fish screens at three diversion dams.	May reduce energy generation or require additional energy
U.S. Bureau of Reclamation and Tehama Colusa Canal Authority	Red Bluff Diversion Dam Fish Passage Project	Includes a new pumping plant and fish screen with a pumping capacity of 2,500 cubic feet per second (cfs). The initial installed pumping capacity will be 2,000 cfs.	May reduce energy generation or require additional energy
U.S. Bureau of Reclamation	Delta-Mendota Canal Intertie Pumping Plant	Construction and operation of a pumping plant and pipeline connection between the Delta Mendota Canal (DMC) and the California Aqueduct. The Intertie would include a 450-cfs pumping plant at the DMC that would allow up to 400 cfs to be pumped from the DMC to the California Aqueduct via an underground pipeline. The additional 400 cfs would bring the Jones Pumping Plant to its authorized amount of 4,600 cfs.	Increased energy demand
Zone 7 Water Agency and Department of Water Resources	South Bay Aqueduct Improvement and Enlargement Program	Increase the existing capacity of the water conveyance system up to its design capacity of 300 cfs, and expand capacity in a portion of the project to add 130 cfs (total of 430 cfs).	Increased energy demand

No Action Alternative

The No Action Alternative is not anticipated to cumulatively effect energy resources in the study area. The combined energy factor for CVP and SWP pumping would be about 1.5 GWh/TAF. Slight variances would be expected from the potential reoperation of reservoirs and energy generation facilities to accommodate changes in future precipitation and water management. Ongoing and reasonably foreseeable future projects that use more energy may also affect regional energy use. However, the No Action Alternative would not create new demand that would cumulatively effect energy resources or the energy use factor for CVP and SWP south of Delta pumping.

The Delta and vicinity are within a highly active seismic area, with a generally high potential for major future earthquake events along nearby and/or regional faults, and with the probability for such events increasing over time. Based on the location, extent and non-engineered nature of many existing levee structures in the Delta area, the potential for significant damage to, or failure of, these structures during a major local seismic event is generally moderate to high. In the instance of a large seismic event, levees constructed on liquefiable foundations are expected to experience large deformations (in excess of 10 feet) under a moderate to large earthquake in the region. While there are no set thresholds for salinity, bromide, or other contaminants at which the Banks and/or Jones Pumping Plants would cease operations, an event that would alter the hydrology of the Delta such that brackish water or seawater is drawn into the southwest portion of the Delta would likely result in these pumps shutting down until freshwater flows can be reestablished and flush the brackish water/seawater from the vicinity of these pumping plants' intakes. (See Appendix 3E, *Potential Seismic and Climate Change Risks to SWP/CVP Water Supplies* for more detailed discussion) Depending on the duration of the interruption, this could result in a substantial decrease in energy use at the SWP and CVP Delta pumping plants. This decrease in energy use could be offset if south of Delta water uses switch to alternative water supplies. To reclaim land or rebuild levees after a catastrophic event due to climate change or a seismic event would create an increase in energy use during construction. While similar risks would occur under implementation of the action alternatives, these risks may be reduced by BDCP-related levee improvements along with those projects identified for the purposes of flood protection in Table 12-13.

Impact ENG-4: Cumulative Impact on Energy Use for Operation of the BDCP Water Pumping and Conveyance Facilities In the Delta

***NEPA Effects:* Alternatives 1A through 8**

For Alternatives 1A through 8, the construction and operation of north Delta intakes and a new Delta conveyance facility from the north Delta to the existing CVP and SWP pumping plants in the south Delta under CM1 would not result in adverse effects on energy use within the Delta region. As indicated in Table 21-11, the amount of energy use each year will depend on the hydrological conditions as well as the specific features of the alternative (i.e., pumping capacity and energy factor). Each of these BDCP alternatives would require an average annual increased energy use of between 18 GWh and 421 GWh, relative to the No Action Alternative (2060), for pumping and conveyance through the Delta. Because all of this electrical energy would be transmitted from existing or new generation facilities to the new pumping plants on the existing transmission grid, other projects that use more energy would contribute cumulatively to this effect on regional energy use (Table 21-13). However, the increase attributable to any alternative compared to statewide use (300,000 GWh) is not cumulatively considerable.

CEQA Conclusion: Each of these BDCP alternatives would require an annual increase energy use, relative to existing conditions. When combined with ongoing and reasonably foreseeable future projects, cumulative energy demand may affect regional resources. However, the increase attributable to any alternative compared to statewide use (300,000 GWh) is not cumulatively considerable. Accordingly, there is no cumulative effect on energy use from Alternatives 1A through 8. This impact would be less-than-significant. No mitigation is required.

NEPA Effects: **Alternative 9**

Alternative 9 would rely on the existing Delta channels (with some dredging) and tidal energy to transport water from the Sacramento River to the existing south Delta channels. Dredging for Alternative 9 would require considerable amounts of diesel fuel during the dredging period (2–3 years), but not much electrical energy would be used. Although some new circulation pumps would be needed as part of the separation of the San Joaquin River corridor from the south Delta pumping plants to reduce fish entrainment, no substantial new energy use would be required. There would be no cumulative effect on energy use from Alternative 9.

CEQA Conclusion: Alternative 9 would rely on the existing Delta channels (with some dredging) and tidal energy to transport water from the Sacramento River to the existing south Delta channels. Although some new circulation pumps would be needed as part of the separation of the San Joaquin River corridor from the south Delta pumping plants to reduce fish entrainment, no substantial new energy use would be required. Accordingly, there is no cumulative effect on energy use within the Delta from Alternative 9. This impact would be less-than-significant. No mitigation is required.

Impact ENG-5: Cumulative Impact on Energy Use at Existing CVP and SWP Pumping Plants to Deliver Additional Water Supplies

NEPA Effects: **Alternatives 1A through 5**

For Alternatives 1A through 5, the operations under CM1 would allow increased Delta exports and water supply delivery compared to the No Action Alternative (2060). Table 21-11 provides a comparative summary of the annual average energy use for additional pumping for increased water supply deliveries to CVP and SWP contractors. This increased pumping is less than the maximum monthly energy requirement planned and previously operated for CVP and SWP water supply deliveries. This increased energy use contributes to the cumulative effects on increased energy use in the South of Delta water supply region. Although this increased energy use at the existing CVP and SWP pumping plants was not considered a project impact on energy resources (the energy sources were planned and constructed as part of the CVP and SWP and therefore do not represent a *new* energy demand), this increased energy use would contribute to the cumulative energy use in this large portion of California. The high energy requirements of the SWP are well described and understood (California Energy Commission 2005; Natural Resources Defense Council 2004) and are a significant factor in the cumulative energy use of the south of Delta water supply region. However, the increase attributable to any alternative compared to statewide use (300,000 GWh) would not be cumulatively considerable.

***CEQA Conclusion*:** Increased energy use for pumping of increased water deliveries to the South of Delta CVP and SWP water supply region could result in cumulative impacts on energy use within the water supply region. This cumulative impact is considered significant but the contribution from Alternatives 1A through 2C, and Alternatives 4 and 5 would not be cumulatively considerable because this energy use is within the planned maximum capacity for the CVP and SWP. Because this energy use is part of the energy uses for existing facilities, the incremental impact from the BDCP alternatives on cumulative energy use in the South of Delta region would be less-than-significant. No mitigation is required.

NEPA Effects: **Alternatives 6A through 9**

Alternatives 6A through 9 each would reduce somewhat the energy used to pump water from the Delta to CVP and SWP contractors because these alternatives would reduce the annual average CVP and SWP south of Delta water deliveries and reduce the average annual energy use, relative to the No Action Alternative (2060), by about 100 GWh/yr to 1,800 GWh/yr, depending on the alternative, (Table 21-11). These alternatives would reduce the cumulative effect on energy use in the CVP and SWP South of Delta water supply region and the increase attributable to any alternative compared to statewide use (300,000 GWh) would not be cumulatively considerable.

CEQA Conclusion: Alternatives 6A through 9 would provide somewhat less CVP and SWP water supply deliveries and would reduce the cumulative energy use for pumping from the No Action Alternative. There would be no cumulative energy impact in the South of Delta water supply region. Accordingly, this impact would be less-than-significant. No mitigation is required.

21.4 References

21.4.1 Printed References

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