# 31. Power Production and Energy

## 31.1 Introduction

This chapter describes the existing electrical generation and transmission infrastructure, the electricity market structure, the electricity demand forecast for California, and the potential effects of Project operations on future power production and use in the Primary, Secondary and Extended study areas. Descriptions and maps of these three study areas are provided in Chapter 1 Introduction.

The regulatory setting for power and energy is discussed briefly in this chapter, and is presented in greater detail in Chapter 4 Environmental Compliance and Permit Summary.

This chapter focuses on the potential impacts to electric power demand and production that could result from operation of the Project. Other energy uses for the Project, including diesel use by construction machinery and electricity use at the Project's recreation facilities, are also discussed. To the extent possible, these discussions are separated into the Extended, Secondary, and Primary study areas. However, due to the highly interconnected nature of the electric grid in the Western Interconnection (made up of all or parts of 14 states, two Canadian provinces, and part of Mexico), the effects of the Project on the delivery and use of electric power in that region are not necessarily limited to the defined geographic study areas, but rather can affect areas throughout the western U.S. Mitigation measures are provided in this EIR/EIS for identified significant or potentially significant impacts, and because no negative power production/use impacts were identified, no mitigation is included in this chapter.

## 31.2 Environmental Setting/Affected Environment

### 31.2.1 Extended Study Area

The Extended Study Area for this analysis includes all areas potentially affected by the changes to power grid operations caused by operation of the Project. The Project is located in northern California; therefore, the initial affected power system is comprised of primarily Pacific Gas & Electric (PG&E), Western Area Power Administration (WAPA), and Transmission Agency of Northern California (TANC) transmission systems, numerous generation facilities located in this area and the distribution systems of various entities interconnected to that portion of the Bulk Electric System (BES). The Extended Study Area also includes all or portions of 14 Western U.S. States, two Canadian Provinces, and the northern portion of Baja California Norte in Mexico that currently comprise the Western Interconnection. [1]

The Western Electricity Coordinating Council (WECC) is the Regional Entity responsible for coordinating and promoting BES reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws. The Balancing Authority (BA) is a key entity charged with complying with many of the reliability standards that WECC implements. The North American Electric Reliability Corporation (NERC) glossary of terms defines BA as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. The California Independent System Operator (CAISO) is the largest BA in northern California. The Balancing Authority of Northern California (BANC) is an important municipal BA that

[1] The Western Interconnection is one of three synchronized interconnections in the United States where electricity can flow freely between various parts of the power system, only limited by transmission capacity and operational constraints.

includes WAPA as a sub BA. Both WECC and CAISO have ongoing efforts to plan for the reliable integration of significant amounts of intermittent renewable generation into the grid.

The states and provinces comprising WECC, along with the 2009 and projected 2020 electric energy demand of each state or province, are shown in Figure 31-1. The electric power grid in California is highly interconnected via high-voltage electric transmission lines with many WECC subregions. The grid is used to move power from a generator in one location to power users in another location; at any one time, millions of customers and hundreds of generators are using the grid for electricity service. The Western Interconnection offers many advantages, such as added system stability due to the inertia contributed by the hundreds of generators connected to the grid at any one time. System inertia is a product of the rotational velocity and mass of the rotors of all generators connected to the grid. The greater the system inertia, the greater ability the system has to mitigate disturbances to the grid, such as a generator shutting down unexpectedly. Some types of renewable generation such as solar photovoltaics do not use rotors to generate electricity and so do not provide inertia to the power system. The interconnected nature of the grid also adds stability due to its inherent tendency to cancel out load variability. For example, when one large load is started in one region, it is probable that the resultant instability put into the interconnected grid would be cancelled by the shutdown of one or more loads in another area. In addition, interconnected grids have the benefit of a more efficient bulk transfer of power and make it possible to serve load at the lowest available marginal cost of generation, provide supply reliability, and provide better outage management. The benefits provided by the interconnected grid have limits, however, especially as power flows on the grid reach maximum capacity and create congestion or bottlenecks that limit the ability to move power from one region to another.

The grid in the Western U.S. and Canada is highly interconnected north and south, such that hydroelectric generation in British Columbia can be delivered to California, and vice versa. Seasonal exchanges[2] without firm transmission rights were once common, but have been mostly crowded out of the market due to congestion in the electric transmission grid. This same congestion can also exacerbate the rare times when faults occurring in one area, such as the sudden loss of a generator or transmission line segment, ripple through vast areas of the West, creating widespread blackouts, such as a 1996 incident in which a downed transmission line in Montana led to a cascading outage across the western U.S., including large parts of California (Venkatasubramanian and Li, 1996), or a September 2011 incident in which a series of electrical faults in Arizona and Mexico led to a blackout for more than five million people in California (CEM, 2011). Interconnection to the eastern WECC subregions, as well as to other BAs in the U.S. and Canada, has always been limited by a relative lack of infrastructure, due to population trends and the difficulties and expense of constructing and maintaining electric transmission lines across the Rocky Mountains and other mountain ranges in the West.

Contractual agreements and electric reliability requirements guide the movement of power over the grid. Changes in supply and demand in any given time period can have both direct physical effects on the grid that can affect system reliability, and effects on the economics and contractual instruments that drive the use and operation of the grid. Short-term effects, such as a decrease in supply due to idling of a large power plant for maintenance, are reflected primarily in the cost of electricity, and in the cost of the fuels used to produce that electricity. Longer term effects, such as the introduction of a new large load, new generation, transmission or market products/design can all cause the need to upgrade the impacted system or region.

[2] Seasonal exchanges occur when winter-peaking utilities in the north send power south during the summer, and summer-peaking utilities in the south send power north during the winter.

### 31.2.2 Secondary Study Area

The Secondary Study Area includes the Balancing Authority Areas of CAISO and BANC from which Project-related transmission services, power sales, and purchases would occur.

#### *31.2.2.1 Electrical Generation*

California's electrical infrastructure is a complex grid of energy generation connected by high-voltage electric transmission lines and lower-voltage distribution lines. Table 31-1 shows the breakdown of sources for electric power consumption in the state in 2009 and 2010. California produces approximately 70 percent of its electricity from power plants within the State and from plants located outside the State but owned by California utilities. Approximately 30 percent of California's power supply is imported electricity from the Pacific Northwest and the American Southwest. In 2010, the total electricity imported was 92,130 gigawatt-hours (GWh), up slightly from 91,140 GWh in 2009. The 1,008 in-State power plants (greater than 0.1 megawatt [MW] each) totaled 69,709 MW in installed capacity and produced 205,695 GWh of electricity in 2009. Utilities in California own approximately 6,200 MW of capacity outside of the State, including all or portions of nuclear power plants in Arizona and coal-fired plants in Arizona, Nevada, New Mexico and Utah (CEC, 2011c). Both demand and total energy use in the State declined from 2009 to 2010, due to a generally cooler year and the downturn in the economy.

**Table 31-1**
**2009 and 2010 Total System Power for California**

| Fuel Type | California In-State Generation (GWh) | California In-State Generation (%) | Northwest Imports (GWh) | Southwest Imports (GWh) | California Power Mix[a] (GWh) | California Power Mix (%) |
|---|---|---|---|---|---|---|
| **2009 Total System Power** | | | | | | |
| Coal | 3,735 | 1.8 | 810 | 19,502 | 24,046 | 8.1 |
| Large Hydro[b] | 25,147 | 12.1 | - | 2,099 | 27,246 | 9.1 |
| Natural Gas | 116,726 | 56.3 | 1,884 | 6,753 | 125,362 | 42.0 |
| Nuclear | 31,509 | 15.2 | - | 7,570 | 39,080 | 13.1 |
| Oil | 67 | 0.0 | - | - | 67 | 0.0 |
| Other[c] | 7 | 0.0 | - | - | 7 | 0.0 |
| Renewables[d] | 29,989 | 14.5 | 5,059 | 743 | 35,791 | 12.0 |
| Biomass | 5,940 | 2.9 | 885 | - | 6,825 | 2.3 |
| Geothermal | 12,907 | 6.2 | - | 738 | 13,645 | 4.6 |
| Small Hydro[e] | 4,044 | 2.0 | 1,052 | - | 5,096 | 1.7 |
| Solar | 850 | 0.4 | - | - | 850 | 0.3 |
| Wind | 6,249 | 3.0 | 3,122 | 5 | 9,375 | 3.1 |
| Unspecified Sources of Power[f] | 0 | 0.0 | 12,177 | 34,535 | 46,712 | 15.7 |
| **Total** | **207,180** | **100.0** | **19,929** | **71,201** | **298,310** | **100.0** |
| **2010 Total System Power** | | | | | | |
| Coal | 3,406 | 1.7 | 783 | 18,236 | 22,424 | 7.7 |
| Large Hydro | 29,861 | 14.6 | - | 1,333 | 31,194 | 10.8 |
| Natural Gas | 109,481 | 53.4 | 1,330 | 10,625 | 121,436 | 41.9 |
| Nuclear | 32,214 | 15.7 | - | 8,211 | 40,426 | 13.9 |
| Oil | 52 | 0.0 | - | - | 52 | 0.0 |

**Table 31-1**
**2009 and 2010 Total System Power for California**

| Fuel Type | California In-State Generation (GWh) | California In-State Generation (%) | Northwest Imports (GWh) | Southwest Imports (GWh) | California Power Mix[a] (GWh) | California Power Mix (%) |
|---|---|---|---|---|---|---|
| Other | 0 | 0.0 | - | - | 0 | 0.0 |
| Renewables | 30,005 | 14.6 | 7,586 | 2,205 | 39,796 | 13.7 |
| Biomass | 5,745 | 2.8 | 1,149 | - | 6,894 | 2.4 |
| Geothermal | 12,740 | 6.2 | - | 673 | 13,413 | 4.6 |
| Small Hydro | 4,441 | 2.2 | 554 | - | 4,995 | 1.7 |
| Solar | 908 | 0.4 | - | 51 | 959 | 0.3 |
| Wind | 6,172 | 3.0 | 5,883 | 1,481 | 13,536 | 4.7 |
| Unspecified Sources of Power[f] | 0 | 0.0 | 14,978 | 19,881 | 34,859 | 12.0 |
| **Total** | **205,018** | **100.0** | **24,677** | **60,492** | **290,187** | **100.0** |

[a]Total of in-state and imported generation by fuel type.
[b]Defined as equal to or greater than 30 MW generating capacity.
[c]Includes other non-renewable fuels, such as petroleum coke.
[d]Includes wind and solar generation.
[e]Defined as less than 30 MW in generating capacity.
[f]The California Air Resources Board as of December 2011 was assessing the fuel sources of all imported power. Fuel source for imported power was not previously reported, and therefore is categorized as “Unspecified.”
Note:
GWh = gigawatt-hours
Source: CEC, 2011b.

Since 1983, 90 percent of all new generation in California was natural gas-fired, consisting primarily of either simple-cycle gas turbine peaker plants generally used for meeting peak power demands or to compensate for sudden changes in demand, and combined-cycle power plants used as intermediate or “load-following” power plants that can ramp power production up or down to meet demand through the day (CEC, 2003; CEC, 2012a). Gas-fired power plants are more efficient than other fossil-fueled plants; easier to site, operate, and permit than other options; and are cleaner than other combustion sources. In the mid-1980s, approximately 25 percent of the power plants were gas-fired. By 2009, approximately 42 percent of the energy used in California came from gas-fired plants. California’s fleet of gas-fired power plants is aging. As shown in Table 31-2, almost 60 percent of the gas-fired generation was built before 1980, and almost 50 percent was built before 1970. The older gas-fired power plants are being modernized and some older generation plants are being retired. As shown in Table 31-3, new generation has also come on line in recent years.

**Table 31-2**
**Age of Gas-fired Electricity Generating Capacity in California**

| On-line Date | Capacity | | |
|---|---|---|---|
| | MW | % of Total Electricity Generating Capacity | Cumulative % of Total Gas-Fired Electricity Generating Capacity |
| 1940s | 285 | 0.72 | 0.72 |
| 1950s | 3,568 | 9.04 | 9.76 |
| 1960s | 9,607 | 24.33 | 34.09 |
| 1970s | 5,511 | 13.96 | 48.05 |
| 1980s | 3,965 | 10.04 | 58.09 |
| 1990s | 2,742 | 6.94 | 65.04 |
| 2000-2009 | 13,805 | 34.96 | 100.00 |
| **Total gas-fired capacity** | **30,888** | | |

Note:
MW = megawatt
Sources: CEC, 2012a; CEC, 2012b

**Table 31-3**
**WECC Transmission Plans by Circuit Mile Additions > 100 kV**

| Region | 2008 Existing | 2009 Existing | Under Construction | 2010-2014 Planned Additions | 2010-2014 Conceptual Additions | 2015-2019 Planned Additions | 2015-2019 Conceptual Additions | Total by 2019 |
|---|---|---|---|---|---|---|---|---|
| Basin | N/A | 12,763 | 189 | 1,508 | 280 | 2,291 | 1,503 | 18,534 |
| Northern California | N/A | 15,531 | 196 | 373 | 350 | - | 2,788 | 19,238 |
| Southern California | N/A | 12,057 | 224 | 410 | 492 | - | 415 | 13,598 |
| Desert Southwest | 15,562 | 15,049 | 26 | 1,129 | 807 | 127 | 253 | 17,391 |
| Northwest Power Pool | 43,255 | 30,431 | 220 | 194 | 20 | 810 | 10 | 31,685 |
| Rocky Mountain Power Area | 12,209 | 12,408 | 238 | 769 | - | 208 | 45 | 13,668 |
| Canada | 21,189 | 21,122 | 162 | 658 | - | 323 | - | 22,265 |
| Mexico | 1,313 | 1,402 | - | 129 | - | 102 | - | 1,633 |
| Total WECC | 120,532 | 120,763 | 1,255 | 5,170 | 1,949 | 3,861 | 5,014 | 138,012 |

Notes:
kV = kilovolt
WECC = Western Electricity Coordinating Council
Source: WECC, 2011.

During all but the most adverse water conditions, 10,928 MW of dependable generating capacity from hydroelectric resources are available to meet peak electricity demand in California during peak use times in July and August (CEC, 2012c). However, its hydroelectric output is highly variable year to year. In Dry years (e.g., 2001), hydroelectricity contributed only 13 percent of the state's total power (when combining both in-state and out-of-state generation). In wet years (e.g., 1983), hydroelectricity contributed 45 percent of the state's power. This variability must be accounted for in long-term planning.

The seasonal nature of its generation, such as the increased levels of generation that occur during spring runoff, can create difficulties in moving the excess power to markets that can use it, but also can greatly affect the electric power marketplace by reducing the price for off-peak power, potentially to negative values, during high runoff periods when hydroelectric projects would otherwise spill water rather than send it through the powerhouse. Hydroelectricity generation can be highly useful as a resource that can quickly ramp power operations up or down to compensate for sudden changes in demand or in generation, such as that caused by the variable nature of solar and wind generation. Used as a "firming" resource, hydroelectricity (with the proper configuration) can augment other renewable power production to provide a more reliable resource for planning purposes.

In November 2008, California's former Governor Arnold Schwarzenegger signed Executive Order S-14-08 to raise the State's renewable portfolio standard (RPS) to 33 percent by 2020 by requiring electricity retail sellers to serve 33 percent of their load with renewable energy by 2020. In the ongoing effort to codify the 33 percent by the 2020 goal, California's Governor Jerry Brown and Legislature passed Senate Bill X1-2 in April 2011. The legislation requires all of California's utilities to obtain 33 percent of their overall electricity generation from renewable resources, like solar and wind, by 2020. Federal policy is also supportive of electricity generation from renewable resources. Department of Interior Secretarial Order 3285, issued on March 11, 2009, "establishes the development of renewable energy as a priority for the Department of the Interior."

The 33 percent renewables target by 2020 triggered the need to plan and build energy storage technologies to sustain grid-reliability and mitigate the inherent fluctuations in solar and wind energy production. Electric transmission grid operators have a limited set of technologies that can be deployed to quickly respond to the uncertainty as net demand changes on the grid, most of them are with limited capacity and/or energy. Hydropower pumped-storage is the leading alternative for grid scale energy storage. An important distinction has to be made between "standalone" pumped-storage assets and those assets capable of pumpback that are an integral component of a conventional hydropower setup. The difference between the two is the limited dispatchability of the latter because of the need to sustain the water delivery objective that a specific project was built to serve in the first place.

Renewable integration is the concept of making available, deploying, and operating generation and/or load resources that are flexible and controllable to ensure the reliability of the electric grid, in response to the inherent variability and uncertainty of renewable generation resources (wind and solar). Nationally, there are ongoing efforts to assess the needs and costs of integrating renewable energy resources as they get developed, deployed, and penetrate different electricity grids. In California, electricity market participants, regulatory agencies, and grid operators are collaborating on developing methodologies and models to identify the State's resources need for renewable integration. Options, such as adding gas turbines to compensate for the variability of renewable energy, are being considered, but these are the least favorite solutions, as they diminish the benefits and purpose of deploying renewable energy resources. Other options, such as energy storage, curtailments, and smart grids are also being considered.

One of the most viable options for renewable integration would be an advanced energy storage installation. Pumped-storage, batteries, compressed air, and flywheels are among the different energy storage technologies available, being developed, and deployed today. Some storage technologies are better suited for short-term and fast response "capacity" applications (batteries, flywheels) that could be used to manage grid imbalances and volatility through regulation services. Others, such as pumped-storage and compressed air are better suited for long-term and intermediate response "energy" applications needed to firm up highly variable wind and solar generation.

Pumped-storage projects can quickly ramp up power operation by releasing water from the upper reservoir (forebay) to the lower reservoir (afterbay) during high-demand periods. Water is then pumped back up from the lower reservoir to the upper reservoir during off-peak hours, often taking advantage of very low wholesale power prices for power available during off-peak periods. Major pumped-storage facilities in California include:

- Pacific Gas & Electric's 1,212-MW Helms Pumped Storage Project in Fresno County (standalone)
- DWR's 644-MW Edward C. Hyatt (Butte County), 126-MW Thermalito (Butte County), and 424-MW San Luis/W.R. Gianelli (Merced County) Pumped-Storage Projects (integral to DWR's Lake Oroville)
- Los Angeles Department of Water and Power's (LADWP) 1,331-MW Castaic Pumped Storage Project in Los Angeles County, which takes advantage of SWP deliveries into Castaic Lake (integral to LADWP's water system)
- Southern California Edison's (SCE) 200-MW Eastwood project in Fresno County (standalone)

#### *31.2.2.2 Electric Transmission System*

California's high-voltage electric transmission system connects the different regions of the State to each other, to varying degrees, as well as to the transmission systems of the surrounding western states, Canada, and Mexico. The degree to which areas are interconnected depends upon the availability of transmission capacity between the areas. These interconnected electric transmission systems allow power purchases and sales to extend beyond State and national borders. More than 300,000 miles of electrical transmission or distribution lines currently cross California, including more than 32,000 miles of high-voltage electric transmission lines (CEC, 2011a).

Originally, California's electric transmission system was built by the utility companies to connect their major load centers to the generation sources. Some generation sources were built close to the load centers, requiring relatively short transmission lines; others, such as hydroelectric plants, were located far from the metropolitan areas they serve. The investor-owned utilities (IOUs) – primarily PG&E, San Diego Gas & Electric (SDG&E), and SCE – built much of the electric transmission lines throughout the state to serve their customers. The federal government, through WAPA, also built major electric transmission systems to deliver power from federally owned hydroelectric dams to load centers throughout the west. These public and private electric transmission systems were operated independently of each other, with some ties to the consumer-owned utilities. An example is LADWP, which developed its own transmission system to connect generation in California, Nevada, Arizona, and New Mexico to load centers in the City of Los Angeles. Over time, as development of new power generation close to the load centers became more difficult, the IOUs and the federal government built high-voltage electric transmission systems connecting California to neighboring states – primarily to import less expensive hydroelectricity from the northwest and thermal power from the southwest.

This network of conductors, switchgear, and transformers allows long-distance sales and purchases of power, with deliveries across the grid paid for through tariffs charged by the electric transmission system owners. When a new load or generator comes on line, power flows over the grid must be reconfigured to accommodate the increase in demand or generation. The physical process of inserting or withdrawing additional power from the grid can reduce reliability and may warrant construction of additional infrastructure, such as upgrading an existing electric transmission line to handle more power, or constructing a new power plant in areas where transmission upgrades are not feasible.

The California electric transmission grid is shown in Figure 31-2. The areas that are highlighted are those that are most heavily used. As shown, both the northern and southern regions of the state have an extensively developed grid system. These two areas are connected primarily through one high-voltage line known as “Path 15.” Path 15 is often congested, hampering the ability to transfer power between northern and southern California. The electric transmission system in northern California is owned largely by the federal government (through WAPA) and PG&E. Transmission system planning is driven by Federal Energy Regulatory Commission (FERC) orders 890 and 1000, WECC economic transmission planning through the Transmission Expansion Planning Policy Committee (TEPPC) and California Transmission Planning Group (CTPG) that was formed in 2009 to jointly plan and coordinate transmission planning activities. The CAISO planning process includes both a grid reliability planning process and a more long-term transmission system planning process for all transmission facilities within its control area, which consists of the service territories of the State’s three largest investor-owned utilities. The reliability planning process compares projected load growth against projected generation reserve margins in all areas within the CAISO control area, identifies potential local reliability problems where available generation may not be able to meet maximum local loads, and identifies where the electric transmission system may be too congested to compensate for a system disturbance, such as an unexpected loss of a major generator or transmission line. The short-term solution to any one reliability problem may be to contract for additional generation capacity within the local area, or to construct additional transmission facilities that would allow more remote generation to serve the local load (CAISO, 2011).

The longer term electric transmission planning identifies transmission upgrades needed to serve future loads, as well as to compensate for changes in generation patterns, such as the renewable power generation being introduced into the grid to meet Renewable Portfolio Standards (RPS), which pursuant to State law require that 20 percent of retails sales of all utilities in the state come from renewable resources by the end of 2013, to 25 percent by the end of 2016, and to 33 percent by the end of 2020. Identified reliability-related transmission projects from the reliability planning process are also considered during the transmission system planning process. When needed, transmission system projects are identified during the California Public Utilities Commission (CPUC) transmission planning process which includes CAISO transmission planning process. The transmission system owner then seeks approval for the project through the appropriate regulatory authority, which for PG&E is the CPUC. As one of four power marketing agencies under the Department of Energy, WAPA has its own approval process for upgrading its transmission facilities, although the rates it charges to recover the cost of improvements are approved by FERC.

Reliability planning is also conducted on a wider scale by WECC (Figure 31-3). As designated by the North American Electric Reliability Council (NERC), WECC is the regional entity that was delegated responsibility to implement NERC’s mandatory reliability standards in the Western Interconnection, and provides an environment for coordinating the operating and planning activities of its members. WECC works closely with PG&E and other California utilities to gather data regarding projected future generation reserve margins and planned transmission upgrades to ensure that reliability standards are met throughout the region.

WECC data show that, of the 120,763 circuit-miles[3] of high-voltage transmission lines in use throughout the WECC region in 2009, 15,531 miles are north of the Path 15 transmission line in northern California, and 12,057 miles are south of Path 15 in southern California. WECC projected in its 2011 Long-Term Reliability Assessment that the total circuit-miles would rise to 138,012 miles WECC-wide, with 19,238 miles located in northern California and 13,598 miles located in southern California in 2019 (NERC, 2010 and WECC, 2011).

### 31.2.2.3 Demand Forecast

Over the 10-year period from 2000 to 2010, census data show that California's population increased from 33.9 million to 37.2 million, representing an average annual compounded growth rate of 0.95 percent. Using an estimate made in 2007, prior to the downturn in the economy, California's Department of Finance projected that over the next decade (2010 to 2020) the state population would increase by 5 million people, for an average compounded growth rate of 1.2 percent (DOF, 2009; DOF, 2007).

The increasing demand for electrical energy is based on growth in both population (i.e., households) and commerce (commercial and industrial businesses). Weather can also significantly influence electricity demand. California's peak load was approximately 54,000 megawatts (MW) of electric power in 2009. For that year, the commercial sector accounted for approximately 37 percent of the state's electricity demand, followed by the residential sector, which accounted for approximately 33 percent, and the industrial sector, at approximately 28 percent. The remaining two percent came from government buildings and lighting, such as streetlights and airport lights. Residential demand is projected to grow by 18 percent over the period 2009 to 2035, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand is projected to increase by 43 percent over that same period, led by the service industries. Industrial electricity demand is projected to grow by nine percent, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce. Increased use in the residential sector will come both from an increased average use per household (i.e., larger homes, more homes with air conditioning, and increased home electronics) and a population increase. Historically, the amount of electricity used per household increased by approximately 0.7 percent per year. This trend is expected to continue, with the decrease in electricity use for home lighting, refrigeration, air conditioning, and heating use as the efficiency of these products improve, balanced against the increase in popularity of consumer electronics (DOE, 2011).

In a 10-year forecast released in November 2007, the California Energy Commission projected that electricity demand in the State would increase at a rate of 1.3 percent per year from 2010 to 2018, with peak demand increasing at an annual average rate of 1.4 percent, and the maximum peak load increasing at an annual rate of 1.35 percent (CEC, 2007a). However, the downturn in the economy in 2009 to 2010 had a significant effect on electricity use in the State, such that the projected maximum demand for the summer of 2011 was actually two percent lower than the projected maximum demand for the summer of 2010 (CEC, 2011a). Across the WECC region, the 2010 total region-wide demand of 148,365 MW is projected to increase by 1.4 percent per year to 168,237 MW in 2019, while California summer and winter total internal demands are projected to increase at annual compound rates of 0.8 percent and 1.2 percent, respectively. California annual energy use is projected to grow at an annual compound rate of 1.2 percent (NERC, 2010). However, these projections are between 2.0 and 6.2 percent lower than the

[3] A circuit-mile is one mile of a single circuit, which for alternating current (AC) circuits are generally three-phase, and therefore, have three separate conductors making up a single circuit. Direct current (DC) circuits consist of two phases, and therefore, have two conductors needed per single circuit.

2009 projections, showing the effect of the downturn in the economy, and the difficulty of accurately predicting future demand.

Electricity use is expected to increase over the long-term, but will be balanced in California by the continued application of cost-effective energy efficiency programs, and replacement of appliances and other devices with more efficient technology. California has led the nation in efficiency gains for decades, with the result that it uses less energy per capita than any other state. California’s 6,721 kWh per capita energy use is approximately half the national average of 12,167 kWh per capita (CEC, 2010).

Demand for electricity in northern California can ebb and flow dramatically, both within each year and from year to year, as can available generation. Demand is highest during heat waves[4] and is generally lowest at night during spring and fall, when heating and cooling demand is low. Competition for off-peak power purchases is much more robust during summer months, as is reflected in the considerably higher market prices. Northern California’s summer peak demand is projected to grow from 25,310 MW in 2010 to 27,502 MW in 2019, for an annual compound growth rate of 0.9 percent. Winter peak demand is expected to grow from 18,155 MW in 2010 to 20,177 MW in 2019, an annual compound growth rate of 1.2 percent. Annual energy use in northern California is expected to grow from 128,119 GWh in 2010 to 140,378 GWh in 2019, for an annual compound growth rate of 1.1 percent (NERC, 2010).

### 31.2.3 Primary Study Area

The Primary Study Area is limited to those areas that would be most directly affected by Project power operations, including the specific transmission lines that the Project would connect to, and other CVP and SWP projects that would be re-operated by the alternatives. The Primary Study Area includes the service territories of entities that currently purchase power from the SWP and CVP.

#### *31.2.3.1 Central Valley Project*

The Central Valley Project, one of the Nation`s major water conservation developments, extends from the Cascade Range in the north to the plains along the Kern River in the south. The CVP is managed by the U.S. Bureau of Reclamation (Reclamation). Initial features of the project were built primarily to protect the Central Valley from water shortages and floods, but the CVP also improves Sacramento River navigation, supplies domestic and industrial water, generates electric power, conserves fish and wildlife, creates opportunities for recreation, and enhances water quality. The CVP is comprised of 20 dams and reservoirs, 39 pumping plants, 11 power plants, and 500 miles of major canals manage nearly nine million acre-feet of water annually, delivering water to customers from Redding to Bakersfield. The CVP includes four major canals: the Tehama-Colusa, the Contra Costa, the Delta-Mendota, and the Friant-Kern. CVP also includes storage reservoirs on the Trinity, Sacramento, American, Stanislaus, and San Joaquin rivers, and offstream storage at San Luis Reservoir.

San Luis Reservoir is part of both the CVP and SWP; it is a pumped-storage operation that takes water from, and makes deliveries to, both the California Aqueduct and the Delta-Mendota Canal, provides storage for later use, and generates up to 424 MW of power. The federal-only portion of the San Luis Unit includes the O’Neill Pumping-Generating Plant and Intake Canal, Coalinga Canal, Pleasant Valley Pumping Plant, and San Luis Drain. The C.W. “Bill” Jones Pumping Plant (formerly the Tracy Pumping Plant) lifts Delta water 197 feet up and into the Delta-Mendota Canal, and moves water through the canal to San Luis Reservoir. Each of the six pumps at the plant is capable of pumping 767 cfs. Farther south,

[4] Heat waves are defined as three or more days of greater than 100-degree temperatures.

Dos Amigo Pumping Plant, a joint CVP and SWP facility located 17 miles south of O'Neill Forebay, lifts water 113 feet to permit gravity flow to the end of San Luis Canal at Kettleman City. The plant contains six pumping units, each capable of delivering 2,200 cfs at 125 feet of head (WAPA, 2004).

Of the water conveyed by the CVP, approximately five million acre-feet is delivered to farms in northern California, and approximately 600,000 acre-feet is delivered to municipal and industrial users. The CVP is a net energy producer. The CVP's hydroelectric facilities produce approximately 5,600 GWh of electricity annually; 1,300 to 1,400 GWh are used by its pumping facilities. Total maximum power production capacity is approximately 2,100 MW; total pumping demand is approximately 600 MW. The CVP facilities most affected by a new pumped-storage hydroelectric project in northern California would be Folsom (1.0 MAF, 221 MW), New Melones (2.4 MAF, 380 MW), San Luis (2.0 MAF, 227 MW), Shasta (4.5 MAF, 710 MW) and Trinity (2.4 MAF, 575 MW). Together, these facilities produced 2,113 MW and 4,557 MWh on average between 2004 and 2010 (Reclamation, 2011).

Production capacity and pumping power vary significantly from year to year and day to day, depending upon hydrological conditions, reservoir levels, and operational constraints such as fish protection measures. For example, for the one-year period beginning in July 2011, the projected effective generating capacity of the CVP was expected to vary between a low of 715 MW (October 2011) and a high of 1,575 MW (July 2011) (Reclamation, 2011).

CVP power is marketed by WAPA, which sells CVP power to preference power customers, primarily to consumer-owned or government entities, including municipal utilities, irrigation districts, public utility districts, Native American tribes, and large government facilities, such as Department of Energy laboratories. As with all power produced by federally owned hydropower facilities, consumer-owned and government entities are given preference to CVP power sales. Approximately 85 preference power customers purchased CVP power in fiscal year 2005, although 71 percent was allocated to just six customers: Sacramento Municipal Utility District, the City of Redding, Silicon Valley Power (City of Santa Clara), the City of Roseville, the City of Palo Alto and the U.S. governmental facilities in the San Francisco Bay Area (TCCA and Reclamation, 2006).

CVP power and energy allocations are based on predicted hydrological conditions, using a long-term generation model that determines available capacity and energy, and the needed reserve margin. Energy available after serving CVP loads plus a reserve margin is called the Base Resource, which is allocated pursuant to long-term contracts for each year based on this formula:

> Base Resource = Gross Generation - Transmission Losses + Project Use Purchase - CVP Use Load - First Preference Customer Load[5]

Energy generation beyond the allocated amounts is marketed by WAPA to preference customers pursuant to long-term contracts, with any surplus sold on a short-term basis to others when available. Customers are generally divided into three groups for the marketing plan: base resource, variable resource, and full load service customers. Base resource customers are those customers that will only receive base resource energy from WAPA. Variable resource customers are customers that opt for base resource firming service and/or supplemental energy from WAPA in addition to their base resource. These first two categories of customers receive approximately 85 percent of the base resource. Full load service customers are

[5]Pursuant to the Trinity River Act of 1955, 25 percent of the power delivered from the CVP's Trinity River Division must be reserved for customers within Trinity County. Similarly, the Rivers and Harbor Act of 1962 authorizing the New Melones Project specified that up to 25 percent of the energy resulting from that project is reserved for customers in Calaveras and Tuolumne counties. Customers receiving energy pursuant to these authorizations are referred to as "First Preference" customers.

customers that will have their total load met by WAPA through a combination of their base resource and additional purchases by WAPA on their behalf. This category of customers receives approximately 15 percent of the base resource.

#### *31.2.3.2 State Water Project*

The SWP is a complex network of 34 storage facilities, reservoirs, and lakes; 20 pumping plants; four pumping-generating plants; five hydroelectric power plants; and approximately 701 miles of open canals and pipelines designed to move water from the Feather River basin and Lake Oroville in northern California to users in the Central Valley and southern California. It is the nation’s largest state-built water and power development and conveyance system, and the largest electricity user in the state. DWR manages the SWP to deliver water to its 29 long-term water contractors and their member water agencies. The service areas of these contracting agencies extend from Plumas County in the north to San Diego County adjacent to the Mexican border. These contractors’ service areas comprise almost one quarter of California’s land area and more than two-thirds of its population. SWP facilities also provide flood control, recreation, and fish and wildlife enhancement. The SWP contractors repay all costs related to project construction and operation, with annual repayments of approximately $1 billion per year (based on 2007 data). Of that amount, operation and maintenance costs account for 30 percent; power purchases, less generation and sales, amount to 20 percent; and bond service payments of principal and interest and repayments for other capital financing account for 50 percent (DWR, 2012).

The SWP has a net energy use of approximately 4,600 GWh, making it the largest single consumer of electric power in California, consuming approximately 2.5 percent of the State’s total electric energy production. In 2007, energy used at the SWP pumping and generating plants totaled 9.77 GWh, and 2.26 GWh was sold to 20 utilities and 22 power marketers (DWR, 2012). SWP energy use and production is highly variable, depending on hydrologic and storage conditions. For example, over the period 1990 to 2001, net energy use varied from a low of 3,421 GWh in 1998 (a very wet year with high hydroelectric production) to a high of 8,171 GWh in 1990 (in the middle of the 1987 to 1992 drought).

The SWP’s hydroelectric plants (Hyatt, Thermalito, Gianelli, Warne, Alamo, Thermalito Diversion, Mojave, and Devil Canyon) have a total generating capacity of approximately 1,475 MW. In northern California, the Hyatt Pumping/Generating Plant pumps water from the Thermalito Afterbay to Lake Oroville, in pumping mode, and also produces power when water is released from the lake to the afterbay. Hyatt has three pumping/generating units, each producing 173,000 horsepower and up to 1,870 cfs of flow in pumping mode, and 113 MW (at 615 feet of static head and 2,850 cfs flow) in generating mode; and three generating units, each capable of producing 106 MW (at 615 feet of static head and 2,800 cfs flow). In total the Hyatt plant has a generating and pumping flow capacity of 16,950 cfs and 5,610 cfs, respectively, and can generate up to 645 MW of power. Just downstream, the 114-MW Thermalito Pumping-Generating Plant is designed to operate in tandem with the Hyatt Pumping-Generating Plant and has generating and pumpback flow capacities of 17,400 cfs and 9,120 cfs, respectively. Thermalito Diversion Dam, four miles downstream of Oroville Dam, creates a tailwater pool for the Hyatt Pumping-Generating Plant and is used to divert water to the 10,000-foot-long Thermalito Power Canal designed to convey generating flows up to 16,900 cfs to Thermalito Forebay and pumpback flows to the Hyatt Pumping-Generating Plant. Storage in Thermalito Forebay and Thermalito Afterbay is used to generate power and maintain uniform flows in the Feather River downstream of the Oroville Facilities. Thermalito Afterbay storage also can be used for pumpback operations, which in total may consume about 390,000 MWh of energy annually. Generation provided by pumpback activity has the potential to contribute approximately six or seven percent to the total annual Oroville Facilities generation of approximately 2.08 GWh per year[6] (DWR, 2012).

Further south (as described above) is the San Luis Unit, part of both the CVP and SWP, consisting of the O'Neill Dam and Forebay, B.F. Sisk San Luis Dam, San Luis Reservoir, William R. Gianelli Pumping-Generating Plant, Dos Amigos Pumping Plant, Los Banos and Little Panoche Reservoirs, and San Luis Canal from O'Neill Forebay to Kettleman City. O'Neill Pumping-Generating Plant takes water from the Delta-Mendota Canal and discharges it into the O'Neill Forebay, where the California Aqueduct (a SWP feature) flows directly. The William R. Gianelli Pumping-Generating Plant lifts water from O'Neill Forebay using eight 63,000 horsepower pumps and discharges it into San Luis Reservoir. During releases from the reservoir, these plants can generate up to 424 MW of electric power by reversing flow through the turbines. Water for irrigation is released into the San Luis Canal and flows by gravity to Dos Amigos Pumping Plant, where the water is lifted more than 100 feet to permit gravity flow to the end of San Luis Canal at Kettleman City.

Moving water through the California Aqueduct is a series of large pumping plants, starting with the Harvey O. Banks Pumping Plant, located 2.5 miles southwest of the Clifton Court Forebay on the California Aqueduct. Farther south along the California Aqueduct, the Chrisman, Edmonston, and Pearblossom pumping plants historically consumed the highest amount of energy. The Chrisman and Edmonston pumping plants provide 524 and 1,970 feet of lift, respectively, to convey California Aqueduct water across the Tehachapi Mountains. The Pearblossom Pumping Plant lifts water approximately 540 feet and discharges the water 3,479 feet above mean sea level, the highest point along the California Aqueduct.

Using gravity on the downhill side of the Tehachapis, flows through the Alamo Power Plant, Mojave Siphon Power Plant, Devil Canyon Power Plant, and Warne Power Plant, together with generation from the William R. Gianelli Plant (located north of the Tehachapis), generated 1.99 GWh of electric energy in 2007, approximately one-fifth of the total energy used by the SWP. The Alamo Power Plant uses the 133-foot head between Tehachapi Afterbay and Pool 43 of the California Aqueduct to generate electricity. The Mojave Siphon Power Plant generates electricity from water flowing downhill after its 540-foot lift by the Pearblossom Pumping Plant. The Devil Canyon Power Plant generates electricity with water from Silverwood Lake with more than 1,300 feet of head, the highest water head in a power plant in the SWP system. The Warne Power Plant uses the 725-foot drop from the Peace Valley Pipeline to generate electricity (DWR, 2012).

SWP manages its loads and generation resources to maximize off-peak pumping load and peak generation to minimize water delivery costs. The SWP's power resources portfolio also includes contracts for power purchases, sales, and exchanges. The SWP is operated as an independent bulk power entity and is interconnected with the PG&E, Southern California Edison (SCE), and WAPA transmission systems. DWR dispatches the SWP's own loads and resources and coordinates its power operations through CAISO. The SWP makes yearly projections for energy needs to ensure it has enough power to make scheduled deliveries. SWP-related pump load is met through SWP generation, long-term, mid-term, and short-term contracts and purchases.

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[6] This value is the average generation from 1982 to 2001.

### *31.2.3.3 Northern California Transmission System*

The transmission system in northern California consists of dozens of high-voltage (230-kV to 500-kV) transmission circuits, most aligned north and south, which connect the region's diverse network of power plants to load centers throughout the State. PG&E, WAPA, and the Transmission Agency of Northern California (TANC)[7] each own major transmission lines in the region, including in the immediate vicinity of the Project. PG&E has more than 18,600 circuit-miles of transmission lines and 141,000 miles of distribution lines connecting its customers from Eureka to Bakersfield. WAPA's 856 circuit-miles of high-voltage transmission lines can deliver power from the Oregon border as far south as the San Luis Reservoir.

As shown in Figure 31-4, four high-voltage transmission lines are located in western Colusa County in the vicinity of Project facility locations, and the Project could interconnect with any or all of these lines. These are:

- A 230-kV WAPA line extending from the Olinda (Vic Fazio) Substation in Shasta County, south through Tehama, Glenn, Colusa, Yolo, Solano, Contra Costa, and Alameda counties to connect to the Jones Pumping Station at the Tracy Substation, and farther south to other pumping plants along the Delta-Mendota Canal. This line distributes power from CVP facilities to federally owned pumping stations.
- Two 230-kV lines owned by PG&E, which roughly parallel the WAPA-owned line along most of its northern California route, including in Glenn, Colusa, Yolo, Solano, Contra Costa, and Alameda counties. These lines are part of PG&E's 230-kV network, which interconnects PG&E's hydroelectric facilities and various other power plants to load centers throughout northern California.
- The COTP, a 500-kV line owned by a consortium of public and private utilities, including TANC, which is comprised of the COTP manager, PG&E, WAPA, the City of Redding, and the Carmichael and San Juan water districts. The COTP extends from the Bonneville Power Administration's Captain Jack Substation in Southern Oregon south to WAPA's Tracy Substation near the CVP's and SWP's delta pumping plants, and on to PG&E's Tesla Substation. It is interconnected with and parallel to the Pacific Intertie, and consists of three segments: a 148.5-mile-long Northern Segment between the Captain Jack Substation and the Olinda (Vic Fazio) Substation in Tehama County; the 190-mile-long CVP Upgrade Segment between the Olinda Substation and the Tracy Substation in San Joaquin County, near the Tracy Pumping Station; and the Tesla Bypass Segment, a seven-mile-long double circuit from the Tracy Substation to an interconnection with the Pacific AC Intertie on PG&E's 500-kV transmission line between the Tesla and Los Banos substations. The COTP also includes the Maxwell Compensation Station, located approximately six miles south of the Funks Reservoir, which helps condition the power on the 500-kV line.

In addition to the large hydroelectric projects of the CVP and SWP, more than 200 power plants are located in the Primary Study Area; most are smaller than 50 MW. Most of the larger power plants in northern California are located near Sacramento or the San Francisco Bay areas. Only a few power plants of any size are located in the five counties surrounding the Project (Tehama, Glenn, Colusa, Lake, and Mendocino counties), the largest of which is PG&E's 660-MW Colusa Generating Station, located approximately three miles north of the proposed Sites Reservoir site (CEC, 2012a). The Colusa

[7] TANC is a joint powers agency created in 1984 by a group of publicly-owned utilities to plan and construct the California-Oregon Transmission Project (COTP).

Generating Station, which began commercial operations in December 2010, interconnects to the two 230-kV PG&E lines described above, and takes water from the Tehama-Colusa Canal for plant use (CEC, 2007b).

# 31.3 Environmental Impacts/Environmental Consequences

## 31.3.1 Regulatory Setting

The California electrical utility sector is regulated at the federal, State, and local levels. Below is a list of federal and State legislation, regulation and policy affecting California's electric utility industry. These regulations are discussed in detail in Chapter 4 Environmental Compliance and Permit Summary of this EIR/EIS.

### *31.3.1.1 Federal Plans, Policies, and Regulations*

- Federal Clean Air Act of 1970 and 1990
- Federal Power Act of 1920, and its various updates, including:
  - Public Utility Regulatory Policies Act (PURPA) of 1978
  - Electric Consumers Protection Act (ECPA) of 1986
  - Energy Policy Acts of 1992 and 2005

### *31.3.1.2 State Plans, Policies, and Regulations*

- California Global Warming Solutions Act of 2006 (AB-32)
- California Clean Air Act of 1988
- The Warren-Alquist Act
- The Electric Utility Industry Restructuring Act of 1996 (AB 1890)
- Diesel Risk Reduction Plan/Diesel Fuel Regulations of 2000
- California Renewables Portfolio Standard Program of 2002 (SB1078)

### *31.3.1.3 Regional and Local Plans, Policies, and Regulations*

- Regional Clean Air Incentives Market (RECLAIM) program for $NO_x$ and $SO_x$ of 1993
- Glenn County General Plan
- Colusa County General Plan

The Glenn County General Plan does not currently address electric power transmission or generating projects. GCID does not own or operate any power facilities, but instead purchases all of its power from WAPA and PG&E.

The Colusa County General Plan, approved in July 2012, endorses renewable energy project development, renewable energy use, and energy conservation; and commercial alternative energy facilities, including solar, wind, and biomass are allowed in the Agriculture General, Agriculture Upland, Industrial, Forest, and Resource Conservation land use designations with a Conditional Use Permit. It also states that any proposed pipeline or transmission line within the county shall be aligned to minimize interference with agriculture and "should be undergrounded to the greatest extent feasible;" and it allows for the development of sustainable energy production facilities within the county on non-prime agricultural lands (Colusa County, 2012).

## 31.3.2 Project Operational Scenario

### *31.3.2.1 NODOS as an Energy Storage Asset*

Energy storage is the concept of storing excess (and/or low cost) energy during low demand periods for later use during high energy demand (and/or high cost) periods. Energy storage technologies, their capital installation costs, and their electricity grid applications vary significantly from one technology to another and from one market to another. Today, pumped-storage is considered to be one of the most viable forms of energy storage, due its high potential capacity and energy (100s MW and 1,000s MWh), and long discharge time (minutes to hours). Other available energy storage technologies include, but are not limited to, batteries, compressed air, capacitors, and flywheels. Most of these technologies are limited by capacity and/or discharge (time of sustained generation).

Typically, pumped-storage setup includes lower and upper reservoirs, interconnected through hydraulic conveyance/conduit, and a pumping-generating plant. The pumping-generating plant would be interconnected to the electrical grid via a switchyard and transmission lines. Sizing the different components of a pumped-storage setup is a complex multidisciplinary exercise (e.g., engineering, economics, and environmental) that is beyond the scope of this chapter. Operating a pumped-storage facility entails pumping the water from the lower reservoir into the upper reservoir when excess and/or low cost energy is available. The consumed energy (minus losses) would be transformed to potential energy through the hydrostatic head of the water stored in the upper reservoir. When there is a need for energy, capacity, and/or ancillary services (including renewable integration services), water would be released from the upper reservoir into the lower reservoir through the hydraulic turbines to generate electricity. The energy (in MWh) generated from releasing a unit volume of water relative to the energy consumed to pump that unit volume of water into the upper reservoir would be the cycle efficiency (or recovery rate) of that specific pumped-storage plant. Cycle efficiency varies with the net head across the pumping-generating units and the discharge of the water at the time of pumping and generation (subject to water surface elevation in the upper and lower reservoirs, and plant efficiencies). Average cycle efficiency of a pumped-storage setup (which would be site- and technology-specific) may range between 70 percent and 80 percent (with new pumping-generating technology units cycle efficiencies are approaching 85 percent).

The Project is being planned as a multi-objective project, and one of these objectives would be pump-back operations. Another objective for the Project would be potential participation in providing renewable integration services to the electrical grid. The Project would perform as an energy storage asset either through daily time-shifting (from off-peak to on-peak hours), or through seasonal-shifting (from low spring demand to high summer demand). The Project’s benefits in this context would be numerous, including economic incentives, GHG emissions reduction, renewable energy integration, system reliability, and transmission support. The Project, through its water diversion and release cycles from the Sacramento River (seasonal-shifting), and/or daily pump-back operations (time-shifting) would perform as an invaluable energy storage asset that could support the State’s electrical grid.

### *31.3.2.2 NODOS Project Operations*

The Project is expected to operate in a similar manner to the San Luis Reservoir/O’Neil Forebay/Gianelli Powerhouse complex without the limitation of age and design of these facilities that do not allow them to operate in a daily pump-back manner. A detailed description of this daily pump-back operation and the associated benefits is provided in the following paragraphs. On a seasonal basis, water would be pumped from the Sacramento River through the existing Tehama-Colusa (T-C) and Glenn-Colusa Irrigation

District (GCID) canals and/or the proposed Delevan Pipeline into Holthouse Reservoir, where it would be lifted as much as 328 feet by the Sites Pumping/Generating Plant into Sites Reservoir throughout the winter and spring months for storage. The water would later be released for irrigation in the Central Valley, or for M&I use for any entity capable of receiving water deliveries from the Sacramento River or the Sacramento-San Joaquin Delta. Water releases from the Project would be coordinated with releases from Trinity Lake, Shasta Lake, Lake Oroville, Folsom Lake, and San Luis Reservoir to obtain the optimal benefits from both systems while still meeting ecosystem goals.

For Project operations, the base assumptions and scenarios used in developing the CALSIM II model were maintained for the different Project components. The CALSIM II model was used to simulate the operations of the Project, as a component of the integrated SWP and CVP operations. The CALSIM II model is a tool that was setup to emulate the operations strategy set forth for the Project, and to help determine many of the Project benefits and impacts. More details on the CALSIM II model formulation are available in Section 31.3.4.2.

For the purpose of modeling the power operations of the Project, three modes for Project operations were identified: Diversion mode (pumping from the Sacramento River to fill up Sites Reservoir); Release mode (generation) from Sites Reservoir to meet Project water release objectives; and a Pump-back mode to better use residual capacities of the different Project components. The Project Pump-back mode is meant to enhance the Project economics by capturing opportunities offered by the energy market (energy price differentials between on-peak and off-peak hours), and to provide the support/products needed to integrate renewable energy (e.g., wind, solar).

In modeling the power needs for the Diversion mode, an optimization strategy was developed to shift most of the pumping operations (i.e., pump load) to off-peak hours, when excess renewable and/or lower GHG emissions energy is available. Therefore, minimizing energy costs of pumping operations, reducing GHG emissions resulting from pumping operations, and potentially providing renewable integration services, yet, maintaining Project water operations objectives. Flat monthly pumping operations would be maintained (where/when applicable, 24 hours a day, seven days a week), for all three diversion points along the Sacramento River, so the Project would maintain its primary objective of capturing excess flood water in the Sacramento River. Once water is diverted from the Sacramento River into Holthouse Reservoir, the rest of the diversion operations (i.e., pumping into Sites Reservoir) could be optimized to better use Sites Pumping Plant capacity, and the available storage in Holthouse Reservoir. It would retain the on-peak diversions from the Sacramento River in Holthouse Reservoir (as scheduled) and to pump that water into Sites Reservoir in the off-peak hours (on a daily basis). The intent of reshaping the Diversion mode is to allow the Project to participate in providing renewables integration services, reduce its GHG emissions, and avoid on-peak high electricity costs. This shift in operations would allow generating facilities to operate during the on-peak hours (through a controlled water release from Sites Reservoir into Holthouse Reservoir), and provide an opportunity to superimpose the Pump-back mode on the Project Diversion mode. In an optimized mode and in the on-peak (or super-peak) hours, Sites Pumping/Generating Plant would be available for generation. In the off-peak hours, the residual pumping capacity would be available to pump the water back into Sites Reservoir.

For the water Release mode (i.e., generation) of the Project, an optimization strategy was developed to shift water releases and generation to the on-peak hours, to be able to displace high GHG generating plants, provide integration services to renewable generation, and to maximize generation revenues from the Project's generation facilities. For this strategy, and to the extent physically possible, all intended daily water releases from Sites Reservoir into Holthouse Reservoir would occur during the on-peak hours (or super peak hours). Incidental to the on-peak releases from Sites Reservoir into Holthouse Reservoir, water would be released into the Terminal Regulating Reservoir (TRR), T-C Canal, and the Sacramento River up to the capacities of these facilities (and within the planned limits for the water release). The residual water in Holthouse Reservoir (from the on-peak Sites Reservoir releases) would be released during the off-peak hours to satisfy water delivery obligations of the Project. A key requirement for this strategy to be effective is that Holthouse Reservoir's active storage would be made available before the beginning of the next on-peak cycle (i.e., next day's cycle). Optimizing the Release mode would better use Sites generation capacity (through shifting renewable generation from off-peak hours, provide renewable integration services, and maximize revenues), and provide an opportunity to superimpose a pump-back operation cycle on the Release mode.

The Project, through its water diversion and release cycles from the Sacramento River and/or daily pump-back operations, would perform as an invaluable renewable integration and an energy storage (resource-shifting) asset that could support the State's electrical grid. If the Project were to deploy variable speed pumping-generating units (a decision would be made during the design stage), then the Project would be able to provide integration services needed to firm up highly variable wind and solar generation. In the pumping mode, some of the Project's pumping load (subject to physical and operational constraints) would follow the variable wind generation (mostly in off-peak hours). In the generation mode, some of the generation capacity would be offered to provide regulation services needed to firm up wind and solar generation (mostly in on-peak hours).

The net result from the Project's operations is that the Project would be able to help the grid by shifting cleaner (renewable energy, including hydropower, or at least energy with lower GHG emissions) resources from the off-peak hours to the on-peak hours. In addition, and if properly equipped with variable speed units, it could provide renewable integration services, thereby displacing single cycle combustion turbines and combined cycle gas turbines, otherwise, it would be needed to firm up renewable energy resources. Although the Project is a net energy consumer, when Project's operations get optimized, the Project would have a positive impact through its ability to perform resource shifting, renewable integration, and lower overall energy market's GHG emissions.

A third component of the Project power operations is a daily pump-back operation. For periods when the Project is in neither Diversion nor in Release modes, Sites Reservoir pumping and generation facilities can operate in a pure pump-back mode to participate in shifting excess renewable energy resources (excess wind energy) from off-peak to on-peak hours, provide renewable integration services needed to firm-up renewable energy resources in both the on-peak and off-peak hours, and reduce overall GHG emissions for the California electrical grid. In a pure pump-back operation mode, water would be released from Sites Reservoir into Holthouse Reservoir during the on-peak (or super peak) hours to generate energy and would be pumped back into Sites Reservoir in the off-peak hours to complete the pump-back cycle. The pump-back operation could be superimposed on the Diversion and Release modes when the energy market economics relative to the Sites Pumping/Generating Plant's efficiency (cycle efficiency) are conducive to do that. At Sites Reservoir, the extent of the pure pump-back operations, and pump-back incidental to the Project diversion and release modes, would be driven by market economics, pumping-generating cycle efficiency, residual pumping capacity, residual generation capacity, and residual storage capacity in Holthouse Reservoir.

It is important to note that Project power operations is likely to be designed to first sustain water delivery objectives, and then to choose whether the residual pumping–generating capacity could be offered in the energy and/or in the ancillary markets (including renewable integration services).

Power delivered to or taken from the Project would be transmitted over the interconnected transmission system through one or more interconnection points. Any one or a combination of the four high-voltage transmission lines that are located near the Project could interconnect with the Project to move power into or out of the Project. A transmission system impact study, conducted by the transmission system owner or owners, would be needed to determine the optimal interconnection costs, as well as to identify potential reliability problems that may be caused by the interconnection, and potential system upgrades needed to mitigate the impact of the new interconnection.

Because of the already highly limited capability of transferring additional power between northern and southern California, the effects of Project operations would occur primarily north of the Path 15 transmission line in central and northern California. This region also effectively represents the service area of the CVP. However, as is shown in the modeling conducted to date as part of analyzing the effects of Project operations on the overall power system, detailed in Section 31.3.4.2, the water operation of the Project would also have a ripple effect on energy use in all of California.

For example, the Project would act as an additional storage facility, up to 1.8 MAF, much like the 2-MAF San Luis Reservoir. During drought years especially, the increased storage would increase operations of several pumping plants as water would be released to the Sacramento River and into the Delta, where it would be pumped into the California Aqueduct and the Delta-Mendota Canal, and on through the SWP or CVP pumping stations to projects’ service areas throughout central and southern California. Any increased storage in northern California would have the same effect: increased flexibility and quantity in storage would allow or cause increased operations of all pumping plants, including at the SWP’s Lake Oroville/Thermalito Complex, where the increased storage of the Project may allow increased pump-back operations there. Increased storage would lead to increased pumping throughout the SWP because of the increased amount of water available to help meet demand while operating within existing environmental restrictions. Increased storage could also lead to increased generation from the SWP and CVP powerhouses from water releases in general.

The diversions from the Sacramento River into Holthouse Reservoir would occur when water is available for diversion. Pumping into Sites Reservoir from Holthouse Reservoir would occur mostly during off-peak hours. From a power perspective, the Project’s pumping load would use excess renewable energy (wind energy), and/or excess capacity from fossil generation units. As a result, the Project would shift renewable energy generated during off-peak hours to on-peak hours. As the modeling for the Project shows, Project pumping and generation for water delivery objectives would be seasonal, with high pumping demand in winter months (December through February) and high generation in summer months.

Pump-back operations would be superimposed on Project operations during periods when the Project is not being operated to meet water delivery objectives, or excess capacities are available and could be better used. The intent would be to optimize Project operations to meet water delivery objectives, and to provide integration services to renewable energy generation plants. The Project represents a medium-sized generator (either 127.6 MW, 130.8 MW, or 141.6 MW, depending upon the alternative), with operations optimized to meet scheduled water releases, and to provide valuable renewable integration services As shown in Tables 31-4 and 31-5, the Project in isolation would represent a large, but mostly off-peak electric load (210 MW to 276 MW, depending upon alternative). This load includes pumping for the water diverted from the Sacramento River to Holthouse Reservoir, including at the T-C Canal (where a new 250-cfs pump would be installed at the Red Bluff Pumping Plant), and at the proposed Delevan Pipeline Intake Facilities. During maximum pumping operations, the Project would have the potential to increase total demand in northern California by as much as 276 MW (181.35 MW at the Sites Pumping/Generating Plant, 65.65 MW at the Delevan Pipeline Intake Facilities, 19.68 MW at the TRR, 6 MW at the Red Bluff Pumping Plant Intake, and 3.39 MW at the GCID Intake).

**Table 31-4**
**Project Maximum Pumping Demand by Alternative**

| Location | Alternative A | Alternative B | Alternative C |
|---|---|---|---|
| Sites Pumping/Generating Plant | 158 MW | 181.35 MW | 181.35 MW |
| Delevan Pipeline Intake Facilities | 65.65 MW | 0 MW | 65.65 MW |
| Terminal Regulating Reservoir | 19.68 MW | 19.68 MW | 19.68 MW |
| Red Bluff Pumping Plant | 6 MW | 6 MW | 6 MW |
| GCID Intake | 3.39 MW | 3.39 MW | 3.39 MW |
| **Total** | **252.72 MW** | **210.42 MW** | **276.07 MW** |

**Table 31-5**
**Project Maximum Generating Capacity by Alternative**

| Generating Plant | Alternative A | Alternative B | Alternative C |
|---|---|---|---|
| Sites Pumping/Generating Plant | 107 MW | 121 MW | 121 MW |
| Delevan Pipeline Intake Facilities | 10.8 MW | 0 MW | 10.8 MW |
| Terminal Regulating Reservoir | 9.8 MW | 9.8 MW | 9.8 MW |
| **Total** | **127.6 MW** | **130.8 MW** | **141.6 MW** |

Note:
MW = megawatt

Pump-back operations would involve the daily procurement of excess renewable energy and relatively low GHG emissions in the off-peak hours (relatively inexpensive power sources) to pump water from the Holthouse Reservoir up to Sites Reservoir and release water during peak hours to generate power and displace energy with relatively higher GHG emissions. Also, Pump-back operations provide flexible load and generation, and would be used to compensate for rapid changes in electric power demand as well as for changes in power production from variable renewable power sources. Although water delivery and power production are given equal weight in the planning goals for the Project, pump-back power operations would likely be secondary to water delivery operations because of the various restrictions on water operations from contracts and from environmental restrictions, but would be optimized within those restrictions to produce the greatest value to support the California electricity grid through providing renewable energy integration services. Pump-back operations from the afterbay to the forebay of each of the two or three (depending upon the chosen alternative) Project pumping/generating facilities would be possible, but only the Sites Pumping/Generating Plant would be used for daily pump-back operations because of the operational limitations placed on the smaller forebays and afterbays of the other Project pumping/generating facilities.

Table 31-6 shows a summary of a preliminary level analysis performed to assess the benefits from optimizing the Project's hydropower operations, including pump-back operations, so it can participate as an energy storage and renewable integration asset using three renewable integration scenarios, and sustain its intended water delivery objectives.

The maximum direct potential adverse effect on the northern California grid from future Project operations would be the instability of the grid caused by simultaneous starting of all Project pumps at a time when insufficient additional generation and transmission capacity would be available to compensate for the resultant instability put into the grid. When started, motors often initially draw 10 or more times their running current as the motor comes up to speed. Motor control designs and pumping management procedures would ensure that pumps are started sequentially, allowing each to come up to speed before the next pump is started, thus reducing the amount of starting current, and resultant instability. Soft-start and motor-generator technology, such as those used at SWP pumping plants, could also be used to reduce starting currents to minimal levels.

Therefore, with appropriate motor control designs and operating procedures in place, the effective maximum adverse direct effect of the Project would most likely be during periods of maximum pumping when generation reserve margins[8] in northern California are low. Indirectly, during times of high demand for water in southern California, Project water releases would cause increased pumping energy use throughout the SWP, especially during drought periods. Low generation reserve margins can occur during summer months when heat waves cause large increases in air conditioning loads, but also during spring and fall months when many generators are off-line for maintenance, reducing the pool of generators available to meet sudden increases in demand or to compensate for other system disturbances, such as the unexpected loss of a transmission line or large generator.

**Table 31-6**
**Summary of Project Optimized Hydropower Operations, including Pump-back Operations**

| | Operational Mode | Average Annual Load-Gen | Wind or Solar Used or Shifted | Baseload Used or Displaced | Firming Energy Displaced |
|---|---|---|---|---|---|
| | | MWh | MWh | MWh | MWh |
| **Alternative A** | | | | | |
| **Scenario 1** | | | | | |
| Excess Wind (80%) + Integration Service (20%) | Pumping | 398,677 | 318,941 | 0 | 79,735 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 242,568 | 194,054 | 0 | 48,515 |
| | | | | | |
| **Scenario 2** | | | | | |
| Excess Wind (50% + Baseload (30%) + Integration Service (20%) | Pumping | 398,677 | 199,338 | 119,603 | 79,735 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 242,568 | 121,284 | 72,770 | 48,515 |
| | | | | | |
| **Scenario 3** | | | | | |
| Baseload (80%) + Integration Service (20%) | Pumping | 398,677 | 0 | 318,054 | 79,735 |
| Resource Shifting (80% + Integration Service (20%) | Generation | 242,568 | 0 | 194,054 | 48,515 |
| | | | | | |

[8] Reserve margin is defined as the difference in percentage between the maximum generating capacity available to serve load in the region, and the total power demand in that region.

**Table 31-6**
**Summary of Project Optimized Hydropower Operations, including Pump-back Operations**

| | Operational Mode | Average Annual Load-Gen | Wind or Solar Used or Shifted | Baseload Used or Displaced | Firming Energy Displaced |
|---|---|---|---|---|---|
| | | MWh | MWh | MWh | MWh |
| **Alternative B** | | | | | |
| **Scenario 1** | | | | | |
| Excess Wind (80%) + Integration Service (20%) | Pumping | 365,728 | 292,583 | 0 | 73,146 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 241,830 | 193,464 | 0 | 48,366 |
| | | | | | |
| **Scenario 2** | | | | | |
| Excess Wind (50% + Baseload (30%) + Integration Service (20%) | Pumping | 365,728 | 182,864 | 109,718 | 73,146 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 241,830 | 120,915 | 72,549 | 48,366 |
| | | | | | |
| **Scenario 3** | | | | | |
| Baseload (80%) + Integration Service (20%) | Pumping | 365,728 | 0 | 292,583 | 73,146 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 241,830 | 0 | 193,464 | 48,366 |
| | | | | | |
| **Alternative C** | | | | | |
| **Scenario 1** | | | | | |
| Excess Wind (80%) + Integration Service (20%) | Pumping | 421,237 | 336,990 | 0 | 84,247 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 261,060 | 208,848 | 0 | 52,212 |
| | | | | | |
| **Scenario 2** | | | | | |
| Excess Wind (50% + Baseload (30%) + Integration Service (20%) | Pumping | 421,237 | 210,619 | 126,371 | 84,247 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 261,060 | 130,530 | 78,318 | 52,212 |
| | | | | | |
| **Scenario 3** | | | | | |
| Baseload (80%) + Integration Service (20%) | Pumping | 421,237 | 0 | 336,990 | 84,247 |
| Resource Shifting (80%) + Integration Service (20%) | Generation | 261,060 | 0 | 208,848 | 52,212 |

Notes:
Load-Gen = Load and Generation
MWh = megawatt-hour

The indirect effects of Project operations on power and energy use, especially during times of high demand for CVP and SWP water releases, are more difficult to identify and assess because of the difficulty in predicting the mix of generating resources that would be available to meet increased power and energy demand, as well as to provide ancillary services to help maintain reliability standards. However, as load increases, less-efficient generation would be added to the mix, to the point that during periods of very high demand, all available power plants would be made available to maintain resource adequacy, including those that are so inefficient that they otherwise remain idle for all but a few days per year. Inefficient power plants also tend to be the oldest and most polluting plants available, and significantly increase systemwide air emissions per MWh when operating.

To help assess the range of potential systemwide effects of the alternatives, DWR and Reclamation have commissioned several modeling efforts that simulate system operations under various scenarios. The modeling conducted regarding the effect of the Project on power operations throughout the CVP and SWP (Appendixes 31A and 31B) show that the increased storage offered by the Project would:

- Increase the flexibility of water operations throughout the year
- Increase operations of all pumped-storage projects in the SWP
- Increase operations of SWP pumping plants due to the increased water releases from the Project

This increased energy use (from the last bullet above) would be offset somewhat by the increased generation available from the Project and from other projects within the CVP and SWP because of the overall increase in water releases. Any overall increase in energy use indirectly caused by the increased storage offered by the Project could be partially offset by the energy or cost savings offered by releasing Project water from storage. Similarly, the increased systemwide flexibility provided by the Project may also allow increased pump-back operations at other facilities, such as at Lake Oroville/Thermalito Complex and San Luis Reservoir/Gianelli.

### 31.3.3 Evaluation Criteria and Significance Thresholds

Significance criteria represent the thresholds that were used to identify whether an impact would be significant. Appendix G of the *CEQA Guidelines* does not include evaluation criteria related to power production and energy. Appendix F of the *CEQA Guidelines* requires a discussion of the potential energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy.

Appendix F includes the following goals:

- Decreasing overall per capita energy consumption
- Decreasing reliance on fossil fuels, such as coal, natural gas, and oil
- Increasing reliance on renewable energy sources

The evaluation criteria used for this impact analysis represent a combination of the Appendix F criteria and professional judgment that considers current regulations, standards, and/or consultation with agencies, knowledge of the area, and the context and intensity of the environmental effects, as required pursuant to NEPA. An adverse effect on power production and energy would occur if an alternative resulted in a substantial expenditure of energy that was not balanced by corresponding beneficial effects (or would result in a wasteful use of energy), or if it would reduce production of renewable energy within the Extended, Secondary, or Primary study areas. Therefore, for the purposes of this analysis, an alternative would result in a significant impact if it would result in any of the following:

- Inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities.
- Inefficient, wasteful, or unnecessary consumption of energy during operational activities.
- A substantial reduction in the generation of renewable energy.

Various thresholds have been used in previous NEPA and CEQA investigations of SWP- or CVP-related projects in determining significance. For this analysis, an adverse effect would potentially occur if the construction, operation, or maintenance activities result in a net energy use that exceeds five percent of the No Project/No Action Alternative energy use for CVP and SWP pumping. The average combined CVP and SWP energy use for pumping and delivery of water from the Delta, including storage in San Luis Reservoir, pumping over the Tehachapi Mountains, and recovery of some of this energy at generating stations along the California Aqueduct, is approximately 7,000 GWh per year. Therefore, a five percent increase would be approximately 350 GWh.

Although all facilities for each alternative would be constructed, operated, and maintained to minimize the energy required to pump and transport water through the CVP and SWP, each would require energy. An increase in joint CVP and SWP pumping energy use of more than five percent would suggest a wasteful use of energy resources to move water supplies through the CVP and SWP; however, the increased energy use must be balanced against the beneficial attributes of the flexible generation provided by each alternative. The five percent threshold is, therefore, a trigger requiring additional analysis of adverse and beneficial effects to determine overall significance.

### 31.3.4 Impact Assessment Assumptions and Methodology

#### *31.3.4.1 Assumptions*

The following assumptions were made regarding Project-related impacts (construction, operation, and maintenance impacts) to power production and energy use:

- Direct Project-related construction, operation, and maintenance activities would occur in the Primary Study Area.
- Direct Project-related operational effects would occur in the Secondary Study Area.
- The only direct Project-related construction activity that would occur in the Secondary Study Area is the installation of an additional pump into an existing bay at the Red Bluff Pumping Plant.
- The only direct Project-related maintenance activity that would occur in the Secondary Study Area is the sediment removal and disposal at the two intake locations (i.e., GCID Canal Intake and Red Bluff Pumping Plant).
- No direct Project-related construction or maintenance activities would occur in the Extended Study Area.
- Direct Project-related operational effects that would occur in the Extended Study Area are related to San Luis Reservoir operation; increased reliability of water supply to agricultural, municipal, and industrial water users; and the provision of an alternate Level 4 wildlife refuge water supply. Indirect effects to the operation of certain facilities that are located in the Extended Study Area, and indirect effects to the consequent water deliveries made by those facilities, would occur as a result of implementing the alternatives.
- The existing bank protection located upstream of the proposed Delevan Pipeline Intake/Discharge facilities would continue to be maintained and remain functional.
- No additional channel stabilization, grade control measures, or dredging in the Sacramento River at or upstream of the Delevan Pipeline Intake/Discharge Facilities would be required.
- DWR and Reclamation would operate the Project primarily as a water storage and delivery project, with an additional primary purpose of providing electric power services within the contractual and legal obligations that restrict water operations.

- To the extent possible within constraints imposed by water delivery operations, power operations would be conducted in such a way as to provide maximum value to the California power system. Pump-back power operations would be limited to the Sites Pumping/Generating Plant.
- The direct Project-related adverse impacts on power production and energy use would primarily relate to its demand on electric power, which would be offset by its beneficial effects of producing flexible generation to integrate renewable power on demand and/or on-peak energy.
- Indirect Project-related impacts on power production and energy use include both the displaced energy used for Project pumping and the energy use associated with the changes in water storage and conveyance that the Project would cause. For instance, although the Project could increase demand for electric power for its pumping operations, later release of water in storage could avoid use of other more energy-intensive water sources, such as deep groundwater.

#### *31.3.4.2 Methodology*

This analysis examines both adverse and beneficial effects of each alternative, and makes a determination of whether an impact would be significant using the significance criteria listed above, and whether feasible mitigation could avoid, eliminate, reduce, or compensate for a significant impact. To determine overall effects, potential adverse effects were balanced with the potential beneficial effects. To help quantify these effects, DWR and Reclamation have conducted extensive computer modeling of the alternatives to assess the potential benefits and impacts of each, including the No Project/No Action Alternative. The modeling conducted to date for this analysis focused on Project-related operations and the resulting direct and indirect effects within the CVP and SWP systems. The modeling did not attempt to predict all power operations in the WECC, or in all of California, for any alternative.

Whether the alternatives would result in significant impacts to power production and energy was determined based on an assessment of:

- Energy requirements and energy use efficiencies for each stage of the alternative.
- The effects on local and regional energy supplies and on requirements for additional capacity.
- The effects on demands for electricity and other forms of energy.
- The effects of the alternative on other energy resources in particular renewable resources.
- A comparison of the alternatives in terms of overall energy consumption and in terms of reducing wasteful, inefficient, and unnecessary consumption of energy.

To examine the range of potential effects of Project operations on the electric power system in the western U.S., computer modeling of CVP, SWP, and Project power and energy use over a wide range of hydrological conditions was conducted, including multiple Dry years as well as Wet years. This modeling was used in a preliminary analysis of the direct and indirect effects of future Project operations on power and energy use in the Primary, Secondary, and Extended study areas.

The power analysis used spreadsheet post-processors to evaluate the power impacts of flow scenarios from CALSIM II operations studies on a monthly time step. CALSIM II is a planning model developed by DWR and Reclamation that simulates operations of the SWP and CVP and areas tributary to the Sacramento-San Joaquin Delta. CALSIM II provides quantitative hydrologic-based information to those responsible for planning, managing, and operating the SWP and CVP. CALSIM II is typically the system model that is used for any interregional or statewide analysis in California.

The following tools used the monthly output from CALSIM II as input to perform power production and benefits analyses. These tools evaluate facility-specific and systemwide generation, load, and net generation:

- LTGen: analyzes CVP facilities
- SWP_Power: analyzes SWP facilities
- NODOS_Power: analyzes existing and proposed Project facilities

These tools estimated average annual energy generation and use at SWP and CVP facilities and at proposed Project generation and pumping facilities, including existing facilities that would be operated differently if the Project is constructed. For generation facilities, the tools estimated average annual energy generation, as well as average annual peaking power capacity, based on projected reservoir levels. For pumping facilities, the tools estimated average annual energy requirements. The tools also checked to determine whether off-peak energy use targets were met. Transmission losses were estimated for both pumping and generation facilities. The methods, assumptions, and results of the LTGen, SWP_Power, and NODOS_Power spreadsheet models are described in Appendix 31B. A summary description of flow and storage conditions associated with the alternatives, based on the CALSIM II model results, is in Chapter 6. The CALSIM II model description and detailed results are included in Appendix 6B.

Flow and storage levels used in the power analysis tool were taken from CALSIM II studies, using the results of the entire simulation period of October 1921 to September 2003. The monthly time step in CALSIM II is not sufficiently granular to evaluate the on-peak and ancillary service benefits associated with a daily pump-back operation. The CALSIM II data was disaggregated to model the daily-pump back feature to optimize generation benefits and minimize the cost of pumping. DWR's Power and Risk Office (PARO) performed two studies. The first phase study (Phase 1) was completed in 2009, in which the designed capacities and the corresponding operational scenarios for the Project's components were analyzed, and some design modifications were recommended. The second phase study (Phase 2) analyzed the three alternatives identified for the Project, relative to the No Project/No Action Alternative, and to optimize power operations (with sustained water operations) to better capture power market opportunities and use the inherent excess capacities (resulting from hydrology swings) for the different components of the Project. The full Phase 1 and Phase 2 reports are included in Appendix 31A.

The analysis of each alternative also included consideration of direct adverse and beneficial effects from Project operations on electric power use and production. Adverse effects include:

- Displaced use of CVP or SWP power for Project pumping operations.
- Increased pumping throughout the CVP and SWP system, especially during drought years, due to the increased storage available at Sites Reservoir.
- Increased competition for off-peak network power purchases for Project pumping operations.

Beneficial effects include:

- Increased use of excess renewable energy (especially wind energy) to serve Project's pump loads during off-peak hours.
- Increased peak power generation and flexibility from Project pump-back power production during peak hours.

- Increased availability of ancillary services from Project operations, including firming other renewable power resources, such as wind and solar power, as well as spinning and non-spinning reserves, frequency support, voltage support, and load-following.
- Increased flexibility of water operations throughout the SWP and CVP may allow increased use of pump-back operations at other facilities to maximize revenues, and increasing the ability to meet contract obligations while maintaining required environmental standards.

These direct effects could cause a ripple effect throughout the SWP and CVP, as well as the PG&E and WAPA transmission systems and the interconnected electric utility system in California and beyond, creating indirect effects as utilities, other generators, and large end-users adjust to the changes in market pricing and availability caused by Project operations. For example, direct effects would include changes in pumping power usage to move Project-stored water to some SWP and CVP service areas. Indirect effects could include a need to construct additional power system infrastructure to compensate for the loss of access to CVP power. The increased availability of peak power created by the Project could avoid the need to construct other infrastructure, such as a gas-turbine peaker plant.

### 31.3.5 Topics Eliminated from Further Analytical Consideration

No Project facilities or topics that are included in the significance criteria listed above were eliminated from further consideration in this chapter.

### 31.3.6 Impacts Associated with the No Project/No Action Alternative

#### *31.3.6.1 Extended Study Area – No Project/No Action Alternative*

#### *Construction, Operation, Maintenance, and Recreation Impacts*

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

The No Project/No Action Alternative includes implementation of projects and programs being constructed, or those that have gained approval, as of June 2009. The impacts of these projects have already been evaluated on a project-by-project basis, pursuant to CEQA and/or NEPA, and their potential for inefficient, wasteful, or unnecessary power production and energy has been addressed in those environmental documents. Therefore, **there would not be a substantial adverse effect**, when compared to Existing Conditions**.**

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

If the No Project/No Action Alternative is implemented, the Project would not be built, and there would be no direct increase in demand for electric power due to the Project, nor would the benefit of additional storage be available, and therefore, no additional pumping through the SWP would occur. Electric power demand and energy use throughout the Extended Study Area would continue to slowly increase as the population increases, and regulatory agencies and investor-owned and consumer-owned utilities would continue to plan and construct improvements to their systems to ensure reliability standards are maintained. Overall, the No Project/No Action Alternative would likely result in a moderately increased overall demand for electric power in the western U.S. when compared to Existing Conditions (2009), due to load growth caused by an increased population. Total maximum electric demand in the western U.S. and Canada would increase from approximately 148,000 MW in 2009, to 159,000 MW in 2014, and to 168,000 MW in 2019. Generation reserve margin (defined as the percentage that total available electric generating capacity exceeds electric demand) in the western U.S. and Canada in 2009 was approximately 29 percent; projected reserve margin in summer 2014 is 39 percent, and for summer 2019 is 33 percent, indicating that sufficient generating capacity would be available to accommodate any new loads added to the system during that time frame (NERC, 2010).

If the No Project/No Action Alternative is implemented, the facilities and operations of the SWP and CVP would continue to be similar to Existing Conditions with the following changes:

- An increase in demands and build-out of facilities associated with CVP contracts of approximately 253,000 acre-feet per year north of the Delta at the future level of development. This is a result of an increase in CVP M&I service contracts related primarily to urban M&I use within the American River Basin (198,000 acre-feet), especially in the communities in El Dorado, Placer, and Sacramento counties.
- An increase in demands associated with SWP contracts, up to full contract amounts, south of the Delta at the future level of development. SWP demands, which under the existing level of development, vary on hydrologic conditions between 3.0 to 4.1 MAF per year, would be at maximum contract amounts in all hydrologic conditions under the No Project/No Action Alternative. This represents a potential 25 percent increase on average in south of the Delta demands pursuant to SWP contracts between existing and future levels of development.
- An increase in non-Project water rights demand of 184,000 acre-feet in the American River Basin.

New urban intake/Delta export facilities include:

- Freeport Regional Water Project
- City of Stockton Delta Water Supply Project
- Delta-Mendota Canal–California Aqueduct Intertie
- Contra Costa Water District Alternative Intake Project and Los Vaqueros expanded storage capacity (160 TAF)
- South Bay Aqueduct rehabilitation, to 430 cfs capacity, from its junction with the California Aqueduct to Alameda County FC&WSD Zone 7

An increase in supplies for Wildlife Refuges including Firm Level 2 supplies of approximately 8,000 acre-feet per year, and Level 4 supplies of approximately 50,000 acre-feet per year at the future level of development. However, Firm Level 2 supplies would be met by CVP contract supply and Level 4 supplies would be met through local water acquisitions in both existing and future levels of development.

For the power sector, new infrastructure would be constructed, as necessary, to maintain reliability standards, and would likely consist of a mixture of transmission system upgrades and development of a diverse mixture of generating resources, especially renewable energy resources as required by the Renewable Portfolio Standards (RPS) mandated by state law, and resources capable of rapid ramp-up and ramp-down operations to more easily accommodate the variable generation of solar and wind generation. Similarly for the water sector, the various agencies and companies involved in water system planning would continue to plan and construct system improvements to ensure adequate water sources are available to meet the demands of their customers and constituents.

Predicting exact infrastructure development for the No Project/No Action Alternative would be speculative; therefore, an assessment of potential impacts of future infrastructure development is not possible or practical at this time. This is due to the uncertainties of future power demand and supplies, although sufficient generation reserve margin is predicted through at least 2019 to accommodate reasonably foreseeable increased demand in electric power or energy. Similarly, predicting the water-related infrastructure development that would occur in the absence of the Project is also difficult. Southern California especially faces significant challenges in retaining existing or obtaining new water supply resources; and although demand for water has remained flat throughout the 1990s and 2000s (through aggressive conservation and efficiency programs and standards), maintaining the current or projected level of supply in the future is uncertain. Lowering aquifer levels in many areas of the State caused by overpumping and/or reduced recharge means that groundwater pumping energy use, and related costs, would likely continue to increase as water is pumped from deeper and deeper depths. Other geographic areas of the State are considering the use of desalination, which is also an energy intensive alternative, as a future supply option. State water policy currently calls for a 20 percent reduction in urban water and associated energy use by the year 2020 (DWR et al., 2010), and effective efficiency and conservation programs would likely continue to be the least-cost alternative to addressing future demand increases or supply reduction; but it is also likely that many water agencies would develop infrastructure to access existing or new water resources, or to improve existing resources, such as through groundwater recharge programs. The construction, operational, and maintenance-related impacts of these projects would be evaluated on a project-by-project basis, pursuant to CEQA and/or NEPA, and their potential for impacts to power levels would be addressed in those environmental documents.

Table 31-7 provides a summary of the predicted changes in power and energy use in CVP, SWP and other related facilities if the No Project/No Action Alternative is implemented. The modeling for the Project using the CALSIM II model of CVP and SWP water and power operations (Appendixes 31A and 31B) shows that net generation and energy use at the CVP,SWP and other related facilities would remain at approximately the same levels for the No Project/No Action Alternative as for Existing Conditions, although the long-term average net generation for all existing facilities is expected to decline from plus 51 GWh to minus 132 GWh because of changes in water operations, as described above. The modeling predicts modest changes in energy use and generation for this alternative when compared to Existing Conditions, although power costs are expected to continue to rise, such that long-term power costs for the SWP pumping plants are expected to increase by nearly 50 percent by 2025 if the No Project/No Action Alternative is implemented, even though actual energy use would increase by only three percent, and therefore, does not meet the five percent threshold requiring additional analysis of energy and power use impacts.

**Table 31-7**
**CVP, SWP, and Other Related Facilities Energy Use (in GWh)[a] – No Project/No Action Alternative**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | No Project/No Action Alternative minus Existing Conditions |
|---|---|---|---|---|
| **CVP Facilities** | | | | |
| Energy Generation | Long-Term[b] | 4,712 | 4,701 | -11 |
| | Dry and Critical[c] | 3,533 | 3,513 | -20 |
| Energy Use | Long-Term | 1,124 | 1,116 | -9 |
| | Dry and Critical | 894 | 878 | -16 |

**Table 31-7**
**CVP, SWP, and Other Related Facilities Energy Use (in GWh)[a] – No Project/No Action Alternative**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | No Project/No Action Alternative minus Existing Conditions |
|---|---|---|---|---|
| Net Generation[d] | Long-Term | 3,588 | 3,585 | -2 |
| | Dry and Critical | 2,639 | 2,635 | -4 |
| **SWP Facilities** | | | | |
| Energy Generation | Long-Term | 4,326 | 4,386 | 59 |
| | Dry and Critical | 3,033 | 2,909 | -124 |
| Energy Use | Long-Term | 7,848 | 8,088 | 239 |
| | Dry and Critical | 6,354 | 6,013 | -340 |
| Net Generation | Long-Term | -3,522 | -3,702 | -180 |
| | Dry and Critical | -3,321 | -3,104 | 217 |
| **Other Related Facilities[d]** | | | | |
| Energy Generation | Long-Term | 0 | 0 | 0 |
| | Dry and Critical | 0 | 0 | 0 |
| Energy Use | Long-Term | 13 | 13 | 0 |
| | Dry and Critical | 11 | 12 | 0 |
| Net Generation | Long-Term | -13 | -13 | 0 |
| | Dry and Critical | -11 | -12 | 0 |
| **All Facilities (CVP, SWP, and Other Related Facilities)[e]** | | | | |
| Energy Generation | Long-Term | 9,038 | 9,087 | 48 |
| | Dry and Critical | 6,566 | 6,422 | -144 |
| Energy Use | Long-Term | 8,983 | 9,214 | 231 |
| | Dry and Critical | 7,257 | 6,901 | -356 |
| Net Generation | Long-Term | 51 | -132 | -183 |
| | Dry and Critical | -694 | -482 | 212 |

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.
[b]Long-Term is the average quantity for the calendar years 1922 to 2002.
[c]Dry and Critical is the average quantity for Dry and Critical years according to the Sacramento River 40-30-30 index.
[d]Other Related Facilities include Tehama-Colusa Canal and Glenn-Colusa Irrigation District Canal pumping facilities.
[e]Energy Use and Net Generation for all facilities does not equal sum of Energy Use and Net Generation for CVP, and SWP, and proposed Other Related Facilities because energy use at Red Bluff Pumping Plant (RBPP) is included in both CVP and Other Related Facilities. Results for RBPP from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

Notes:

CVP = Central Valley Project
GWh = gigawatt-hours
SWP = State Water Project

The No Project/No Action Alternative would not support the CEQA Appendix F goals of decreasing per capita energy consumption, decreasing reliance on fossil fuels, and increasing reliance on renewable energy resources, when compared to Existing Conditions. Additional infrastructure would likely be constructed to meet reliability standards, and to allow better integration of variable renewable energy resources into the grid. Projected generation reserve margins indicate that sufficient generation resources would be in place for any increase in demand in any area of the western U.S., and the present planning process that is in place to assure reliability standards are met has proved effective in planning and implementing needed system improvements.

Although the exact nature of future infrastructure development is uncertain, the power and water resource and reliability planning regime currently in place would continue to ensure that utility infrastructure and resources would be sufficient to meet reliability standards, and that all infrastructure and generating capacity built would comply with all applicable laws, ordinances, regulations, and standards; therefore, the No Project/No Action alternative is not expected to result in inefficient, wasteful, or unnecessary energy use and **would not have a substantial adverse effect**, when compared to Existing Conditions**.**

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

The No Project/No Action alternative is not expected to result in a reduction in the generation of renewable generation. The RPS requirement for renewable energy purchases by the State's electric utilities would continue to drive development and integration of renewable energy generation, and the current system reliability processes would ensure that sufficient infrastructure is in place to compensate for the variable nature of solar and wind generation. Therefore, **there would not be a substantial adverse effect** to power production or energy use in the Extended Study area, when compared to Existing Conditions.

### *31.3.6.2 Secondary Study Area – No Project/No Action Alternative*

#### *Construction, Operation, Maintenance, and Recreation Impacts*

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

Refer to the **Impact Power-1** discussion for the Extended Study Area. The discussion also applies to the Secondary Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

The effects of the No Project/No Action Alternative on power production and energy use, when compared to Existing Conditions in the Secondary Study Area, would be similar to that described for the Extended Study Area.Total maximum load in California in 2009 was approximately 59,000 MW, with a generation reserve margin of approximately 28.5 percent; projected California load in 2014 is 61,621 MW, with a generation reserve of 60.3 percent; and projected California load in 2019 is 64,655 MW, with a generation reserve of 53 percent (NERC, 2010). Similar to that described for the Extended Study Area, predicting exact infrastructure development if the No Project/No Action Alternative is implemented would be speculative. Similar to that for the Extended Study Area, the computer modeling effort that was conducted predicts that net SWP/CVP energy use would not increase by five percent or more in the Secondary Study Area if the No Project/No Action Alternative is implemented, and therefore, does not meet the threshold for requiring additional analysis for significance. Therefore, with sufficient planning, the No Project/No Action alternative is not expected to result in inefficient, wasteful or unnecessary energy use, and **would not have a substantial adverse effect.**

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Refer to the **Impact Power-3** discussion for the Extended Study Area. The discussion also applies to the Secondary Study Area.

#### *31.3.6.3 Primary Study Area – No Project/No Action Alternative*

***<u>Construction, Operation, Maintenance, and Recreation Impacts</u>***

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

Refer to the **Impact Power-1** discussion for the Extended Study Area. The discussion also applies to the Primary Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

Total maximum load in northern California in 2009 was approximately 25,000 MW, with a generation reserve margin of approximately 23.5 percent; projected northern California load in 2014 is 26,645 MW, with a generation reserve of 48.7 percent; and projected northern California load in 2019 is 27,502 MW, with a generation reserve of 39.5 percent. Similar to that for the Extended and Secondary study areas, sufficient generation reserve margin in the Primary Study Area is predicted through at least 2019, and the power resource and reliability planning regime currently in place would continue to ensure utility infrastructure and resources would be sufficient to meet reliability standards. Therefore, the No Project/No Action Alternative is not expected to result in inefficient, wasteful or unnecessary energy use, and **would not have a substantial adverse effect.**

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Refer to the **Impact Power-3** discussion for the Extended Study Area. The discussion also applies to the Primary Study Area.

### 31.3.7 Impacts Associated with Alternative A

#### *31.3.7.1 Extended Study Area – Alternative A*

***<u>Construction, Operation, Maintenance, and Recreation Impacts</u>***

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

If Alternative A is implemented, Project construction, maintenance, and recreation activities within the Extended Study Area would not occur, resulting in **no impact**, when compared to Existing Conditions and the No Project/No Action Alternative.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

When compared to Existing Conditions, Alternative A would result in a net increase in maximum demand in the Extended Study Area of approximately 253 MW for Project pumping power, and a net increase in generating capacity of 127.6 MW. When compared to the No Project/No Action Alternative, the net change in demand and generation caused by implementation of Alternative A would likely be approximately the same, based on normal load growth and the processes in place to ensure sufficient water supply and electric power generation and transmission capacity remain in place to meet reliability standards.

The Project's water operation and pump-back operations would be optimized to maintain the best and efficient use of Project's pumping and generating assets. Most pumping from Holthouse Reservoir into Sites Reservoir would be done during off-peak and shoulder hours when power demands (and power prices) are low. During these periods, it is anticipated that there would be an excess in wind generation and there would be a need for load to keep combined cycle gas generation units (low GHG emissions) at the minimum allowed generation. Water stored in Sites Reservoir would represent stored energy in the context of power operations of the Project. Stored water (i.e., energy) would be released through Project generating facilities during on-peak and super-peak hours, either on a seasonal basis to meet water delivery objectives, or on a daily basis to meet pump-back power operations objectives. Either way, the generated power would likely displace single-cycle gas generation units. The net result is that the Project could help to lower overall GHG emissions from the generating sector by shifting cleaner/lower GHG emission resources from the off-peak hours to the on-peak hours. Although the Project would be a net energy consumer, Project operations, when optimized, would have a positive effect in integrating renewable energy resources and lower overall energy market's GHG emissions.

Power would be procured for Alternative A pumping operations from CAISO or WAPA, including power needed for pump-back operations. The increased demand caused by Alternative A pumping would be partially offset by the generating capacity from Alternative A power operations.

Maximum electric demand for Alternative A pumping would equal approximately 0.17 percent of the total 2009 electric demand in the Western Interconnection, and would reduce generation reserve margin by that amount during maximum pumping operations. Alternative A pumping load would be approximately 0.16 percent of total load in that region in 2019. When operated at maximum generating capacity, the Alternative A would add approximately 0.07 percent to the 2009 generation reserve in the same region; it would add approximately 0.06 percent in 2019.

When compared to the entire Western Interconnection, this increase in demand or generation would not be significant, although the addition or sudden loss of Alternative A pumping load or generation could have a ripple effect on the interconnected grid in the western U.S. and Canada, potentially creating cascading reliability problems similar to what occurred during the 1996 electric blackouts in the western U.S. and Canada, where faults occurring in Montana and Idaho created blackouts in California and other parts of the West.

The timing of power use and generation is also important. Project modeling indicates that Alternative A-related pumping would occur mostly in winter months, with lesser amounts into spring and early summer. The modeling also predicts that high generated power levels at the Project would occur mostly during summer months, when water is released to meet CVP and SWP obligations. This matches well for northern California's power system, which has peaks in power and energy use in summer months during periods of high air conditioning demand, and generally has significantly lower demand in winter months.

Alternative A water operations, however, would have a ripple effect on power use and generation throughout the CVP and SWP system, as is examined in the Project modeling that is summarized in Appendixes 31A and 31B. Alternative A water releases in summer months can be partially moved as far as southern California through SWP canals and pumping stations, causing increased energy use at all affected pumping plants.

As shown in Table 31-8, the modeling results for implementation of Alternative A indicate relatively modest effects on generation reserves, and modest increases in energy use of the CVP and SWP as a result of adding the Project facilities to their systems, as would be expected for any increase in water storage in northern California. Table 31-8 does not show the increase in ancillary service production, which would serve to increase system reliability. When considered alone, the energy use by Alternative A would not exceed the 350 GWh trigger requiring additional analysis, whether compared to Existing Conditions and the No Project/No Action Alternative.

**Table 31-8**
**CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative A**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | Alternative A | Alternative A Minus Existing Conditions | Alternative A Minus No Project/No Action Alternative |
|---|---|---|---|---|---|---|
| **CVP Facilities** | | | | | | |
| Energy Generation | Long-Term[b] | 4,712 | 4,701 | 4,711 | -1 | 11 |
| | Dry and Critical[c] | 3,533 | 3,513 | 3,500 | -34 | -13 |
| Pumping Energy Use | Long-Term | 1,124 | 1,116 | 1,152 | 27 | 36 |
| | Dry and Critical | 894 | 878 | 902 | 8 | 24 |
| Net Generation[d] | Long-Term | 3,588 | 3,585 | 3,560 | -28 | -25 |
| | Dry and Critical | 2,639 | 2,635 | 2,598 | -41 | -37 |
| **SWP Facilities** | | | | | | |
| Energy Generation | Long-Term | 4,326 | 4,386 | 4,491 | 165 | 105 |
| | Dry and Critical | 3,033 | 2,909 | 3,143 | 110 | 234 |
| Pumping Energy Use | Long-Term | 7,848 | 8,088 | 8,442 | 594 | 354 |
| | Dry and Critical | 6,354 | 6,013 | 6,768 | 414 | 755 |
| Net Generation | Long-Term | -3,522 | -3,702 | -3,951 | -429 | -249 |
| | Dry and Critical | -3,321 | -3,104 | -3,625 | -304 | -521 |
| **Proposed Project Facilities[d]** | | | | | | |
| Energy Generation | Long-Term | 0 | 0 | 126 | 126 | 126 |
| | Dry and Critical | 0 | 0 | 129 | 129 | 129 |
| Pumping Energy Use | Long-Term | 13 | 13 | 229 | 217 | 216 |
| | Dry and Critical | 11 | 12 | 184 | 172 | 172 |
| Net Generation | Long-Term | -13 | -13 | -103 | -90 | -90 |
| | Dry and Critical | -11 | -12 | -54 | -43 | -43 |
| **All Facilities (CVP, SWP, and Proposed Project)[e]** | | | | | | |
| Energy Generation | Long-Term | 9,038 | 9,087 | 9,329 | 290 | 242 |
| | Dry and Critical | 6,566 | 6,422 | 6,771 | 206 | 350 |
| Pumping Energy Use | Long-Term | 8,983 | 9,214 | 9,818 | 835 | 604 |
| | Dry and Critical | 7,257 | 6,901 | 7,850 | 592 | 948 |
| Net Generation | Long-Term | 51 | -132 | -499 | -550 | -367 |
| | Dry and Critical | -694 | -482 | -1,085 | -391 | -603 |

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

[b]Long-Term is the average quantity for the calendar years 1922 to 2002.

[c]Dry and Critical is the average quantity for Dry and Critical years according to the Sacramento River 40-30-30 index.

[d]Proposed Project Facilities include Tehama-Colusa Canal and Glenn-Colusa Irrigation District Canal pumping facilities.

[e]Energy Use and Net Generation for all facilities does not equal sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant (RBPP) is included in both CVP and Project facilities. Results for RBPP from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

Notes:

CVP = Central Valley Project
GWh = gigawatt-hours
SWP = State Water Project

However, by making up to 1.27 MAF of additional storage available to the water system, water releases from Alternative A would lead to increased use of energy for pumping the released water as far as southern California. According to the modeling results, the net CVP and SWP energy use increase caused by Alternative A (energy use minus energy production) would be as much as 550 GWh more than Existing Conditions and as much as 367 GWh more than the No Project/No Action Alternative, both of which are above the threshold requiring additional analysis. When compared to 2009 total electrical energy use of 858,793 GWh in the Extended Study Area, and projected 2019 energy use of more than 1 million GWh, the increased energy use caused by Alternative A in 2025 would be 0.04 percent of the projected total electrical energy use in the Extended Study Area. However, Alternative A would also create beneficial effects, such as increasing the flexibility of both the electric system and water system in California in meeting demand and maintaining reliability standards, due to the power and ramping capability that Alternative A would create. Project facilities would be designed and built to the maximum feasible efficiency, and both water and power operations would provide considerable benefit to the citizens of the State; therefore the energy used to store water would not be considered an inefficient, wasteful, or unnecessary use of energy because it would be used to store water and potential electric energy for later use when needed. This would result in **no impact**, when compared to Existing Conditions and the No Project/No Action Alternative**.**

#### *Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy*

For the Project, and in addition to the aforementioned seasonal operational profile, pumping-generating assets would be optimized on daily basis to better use and synchronize the Project's facilities with power market opportunities (e.g., prices, ancillary services). The optimized operations would shift all pumping from Holthouse Reservoir to Sites Reservoir to off-peak and shoulder hours, and would shift all water releases and incidental power generation to super-peak and on-peak hours. The benefits from optimized operations of the Project would not only enhance the economics of the Project (minimize net energy costs), but would also make the Project's facilities available to superimpose a pump-back operation cycle on Project operations. It is important to note that through pump-back operations, the Project would be able to offer renewable integration services to the grid and would reduce the overall GHG emissions through shifting excess renewable energy from off-peak hours to on-peak hours. This would, therefore, displace on-peak high GHG emissions generating assets, such as single-cycle combustion turbines.

Alternative A would not likely decrease per capita energy consumption in the Extended Study Area, but would promote increased reliance on renewable resources, decreased reliance on fossil fuels, and reduce greenhouse gas emissions by displacing high emission peaking power plants due to its ability to assist integration of variable renewable power resources, such as wind and solar. Therefore, Alternative A is expected to promote the use of renewable energy, and would not cause a reduction in generation of renewable energy. Therefore, operation of Alternative A would result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### *31.3.7.2 Secondary Study Area – Alternative A*

### *Construction, Operation, Maintenance, and Recreation Impacts*

#### *Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities*

The only use associated with the Project that would occur in the Secondary Study Area, but not in the Primary Study Area, is that associated with the installation and operation of a pump at the Red Bluff

Pumping Plant. Installing the proposed pump into an existing bay at the existing Red Bluff Pumping Plant would require the direct and indirect use of energy resources. Direct energy use would involve using petroleum products and electricity to operate construction and maintenance equipment, as well as fuel use by workers commuting to and from the Project site. Indirect energy use would involve the consumption of energy to extract raw materials to manufacture the pump and construction/maintenance equipment and vehicles, and to transport the pump. These activities would require the use of gasoline and diesel fuel.

Project construction activities would temporarily increase energy consumption during the Project construction period, when compared to Existing Conditions. No substantial long-term energy use would be required for the installation of the pump as part of Alternative A. Also, it is not anticipated that such energy use would be inefficient, wasteful, or unnecessary. This impact is considered to be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative**.**

Various types of fuel-consuming equipment would be necessary for maintenance of the pump (including routine inspections and repairs); however, this additional energy use would be relatively minor when compared to overall maintenance energy use at the facility that currently occurs (i.e., Existing Conditions) and the No Project/No Action Alternative, and the energy usage would be temporary and intermittent. Also, it is not anticipated that such energy use for Project maintenance would be inefficient, wasteful, or unnecessary because it would ensure that the pump would continue to operate properly for its designed life cycle. Impacts to power and energy use related to Project maintenance would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative. In addition, no Project Recreation Areas would be constructed within the Secondary Study Area if Alternative A is implemented, resulting in **no impact** on power and energy use in the Secondary Study Area for Recreation Area maintenance and use, when compared to Existing Conditions and the No Project/No Action Alternative.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

Although Alternative A power operations would have some effects across the Western Interconnection, its major effects would occur in California, due to its effect on CVP and SWP operations. Maximum electric energy demand for Alternative A pumping would equal approximately 0.43 percent of the total 2009 electric demand in California, and may reduce reserve margin by that amount only if pumping occurs during super peak hours. Alternative A pumping demand would represent approximately 0.41 percent of total projected demand in 2014, and 0.39 percent of total demand in 2019. When operated at maximum generating capacity, the Alternative A would add approximately 0.17 percent to the 2009 generation reserve in the same region. In comparison to the all of California, this increase in demand or generation would not be significant.

When compared to 2009 total electrical energy use of 285,913 GWh in the Secondary Study Area (California), and projected 2019 energy use of 321,649 GWh, the increased energy use caused by Alternative A in 2025 (390 GWh) would be 0.14 and 0.12 percent, respectively, of the projected total electrical energy use in the Secondary Study Area. Similar to that for the Extended Study Area, the energy use of Alternative A would not be considered inefficient, wasteful, or unnecessary, and the water stored through that energy use would provide substantial benefits both to power and energy use and to water resources, resulting in a **less-than-significant impact**, when compared to Existing Conditions and the No Project/No Action Alternative**.**

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Regarding the power and energy use goals set forth in Appendix F of the *CEQA Guidelines*, Alternative A would not decrease per capita energy consumption in the Secondary Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Therefore, the Project is expected to promote use of renewable energy, and would not cause a reduction in generation of renewable energy. Operation of Alternative A would result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### *31.3.7.3 Primary Study Area – Alternative A*

### *Construction, Operation, Maintenance, and Recreation Impacts*

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

Power production and energy use within the Primary Study Area during Project construction and/or maintenance activities, and during recreation use, is not expected to be inefficient, wasteful, or unnecessary if Alternative A is implemented.

The proposed modification or demolition of existing facilities, as well as the construction of new facilities, would require the direct and indirect use of energy resources. Direct energy use would involve using petroleum products and electricity to operate construction equipment, such as trucks, bulldozers, and tunnel boring equipment, as well as fuel use by workers commuting to and from the Project sites. Indirect energy use would involve consuming energy to extract raw materials, manufacture construction equipment and materials, and transport the goods necessary for construction and maintenance activities. These activities would require the use of gasoline and diesel fuel.

The use of fuel-consuming equipment during Project construction would increase energy consumption from Existing Conditions temporarily during the Project construction period. No long-term energy use would be required for construction of Alternative A. Also, it is not anticipated that such energy use would be inefficient, wasteful, or unnecessary. This impact would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

Various types of fuel-consuming equipment would be necessary for maintenance of all proposed Project facilities (including routine inspections and repairs), such as sediment removal/dredging, and for maintenance and use of the Recreation Areas. Work conducted during maintenance activities would be relatively minor, when compared to overall energy use in the Primary Study Area for Existing Conditions and the No Project/No Action Alternative, and the energy usage would be temporary and intermittent. Also, it is not anticipated that such energy use would be inefficient, wasteful, or unnecessary because it would ensure that the facilities would continue to operate properly for their designed lifetimes, and would provide benefits to the State. Depending on the activity undertaken at the Recreation Areas, recreation use may require energy in the form of electricity and/or gas; this would also be temporary and intermittent. Impacts to power and energy use related to Project maintenance and recreational use would, therefore, be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

### *Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities*

Other than for Project pumping, energy use during Project operations would be minimal, limited to lighting and potable water pumping proposed for the Stone Corral and Peninsula Hills recreation areas, and the lighting of Project facilities. These areas would use minimal amounts of energy on an ongoing basis, when compared to Project pumping, and do not reach the trigger thresholds requiring additional analysis. Therefore, impacts to power and energy use at the Stone Corral and Peninsula Hills recreation areas, and the lighting of Project facilities would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

Maximum electric demand for Alternative A (252.7 MW) would equal approximately 1.0 percent of the total 2009 electric demand in northern California, and would reduce generation reserve margin by that amount in the State during maximum pumping operations. Alternative A pumping demand would be approximately 0.95 percent of total demand in the region 2014, and 0.92 percent of total demand in 2019. When operated at maximum generating capacity, Alternative A would add approximately 0.41 percent to the 2009 generation reserve in the same region; Alternative A would add a projected 0.32 percent of total northern California generation capacity in 2014, and 0.33 percent in 2019.

A preliminary transmission interconnection feasibility analysis conducted in 2007 concluded that power flows expected for Alternative A, using the assumptions at that time, could be accommodated within the then-existing transmission system, with no upgrades, without creating reliability impacts in the Primary Study Area. Three Interconnection Configuration Alternatives were considered for power flow analysis and cost estimating:

- Interconnect to PG&E's (then-proposed but now operating) Colusa 230-kV Switching Station via a 1-mile 230-kV transmission line
- Interconnect by looping onto PG&E's 230-kV transmission line from the then-proposed Colusa Switching Station to Vaca-Dixon 230-kV substation, circuit #3
- Interconnect by looping onto WAPA's Olinda - Obanion 230-kV transmission line

Power flow analysis showed that all three interconnection points had acceptable NERC/WECC Category A, B and C performance and the Project would not cause any criteria violations. The results of the power flow analysis did not identify a preferred interconnection alternative because all three were feasible and would not require any associated transmission network upgrades (USE, 2007).

By making up to 1.27 MAF of additional storage available to the water system, water releases from Alternative A could lead to increased use of energy. Adverse energy use effects from Project operations are likely to be very small when compared to total energy use in the Primary Study Area. The modeling projects up to a 550-GWh increase per year in energy use by CVP and SWP facilities with implementation of Alternative A, when compared to Existing Conditions and the No Project/No Action Alternative. The increase in energy consumption would be less than 1 percent of 2009 total electrical energy use of 124,405 GWh in the Primary Study Area (northern California), and projected 2019 energy use of 140,378 GWh. The increased CVP and SWP energy use caused by Alternative A in 2025 and 2060 would be 0.29 and 0.26 percent, respectively, of the 2009 and projected 2019 total electrical energy use in the Primary Study Area.

This net increase in power and energy use would likely be accommodated by proper planning, especially given the projected large generation margins in the region. However, operation of Alternative A could cause changes in energy production and transmission patterns that could lead to localized effects, such as a need to build additional infrastructure to compensate for changes in power flows. Determining the future need for new infrastructure due to direct or indirect effects of Alternative A operations would be speculative, given the changes that are likely to happen before Alternative A could be operational. However, all future infrastructure additions would be subject to environmental review by the approving agency, thereby assuring that the environmental effects of such addition would be fully analyzed, with appropriate mitigation imposed for all identified significant impacts.

Alternative A would offer as a benefit to the electric power system in northern California the ability to effectively store energy through pump-back operations. Currently, pumped-storage hydroelectric projects are among the best available technologies to store energy on a large scale, using surplus power during times of low cost to pump water to a higher elevation for later release, with accompanying power production, during times of high demand and high cost.

When compared to all of northern California, the increase in power and energy use caused by Alternative A operations would likely result in a **less-than-significant impact**, when compared to Existing Conditions and the No Project/No Action Alternative, and would not be inefficient, wasteful, or unnecessary when considering the benefits that Alternative A would offer to the electric power system in northern California.

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Alternative A power capabilities would also offer benefits to the system through its ability to firm up the generation of renewable power resources in the region, and especially for solar- and wind-powered resources. It would also offer benefits through its capability to provide ancillary services to the grid. Alternative A power operations would bring stability to the grid by providing the ability to quickly ramp power generation up or down to balance sudden unexpected changes in solar and/or wind generation and compensate for uncertainties in load forecasts (water operations are a primary objective). Alternative A operations could provide ancillary services to the grid in the Primary Study Area by curtailing power use for pumping (up to 253 MW in essentially instantaneous reduction for Alternative A), as well as by ramping up power production (up to 127.6 MW).

Similar to that for the Secondary Study Area, Alternative A would not likely decrease per capita energy consumption in the Primary Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Operation of Alternative A would, therefore, result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### 31.3.8 Impacts Associated with Alternative B

#### *31.3.8.1 Extended Study Area – Alternative B*

***Construction, Operation, Maintenance, and Recreation Use Impacts***

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

The impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Extended Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

Impacts on power production and energy use if Alternative B is implemented are expected to be similar to those described for Alternative A, except that Alternative B would have a somewhat reduced total electric demand for Project pumping operations (210 MW instead of 253 MW), and a somewhat higher generating capacity (131 MW instead of 128 MW). When compared to Existing Conditions, Alternative B would result in a net increase in maximum demand in the Extended Study Area of approximately 210.4 MW for Project pumping power, and a net increase in generating capacity of 130.8 MW. However, the net change in demand and generation caused by development of Alternative B would likely be approximately the same as for Existing Conditions and the No Project/No Action Alternative, based on normal load growth and the processes in place to ensure sufficient water supply and electric power generation and transmission capacity are available to meet system requirements.

Table 31-9 summarizes the modeling results of the CVP and SWP systemwide effects of Alternative B, showing the resultant changes in energy use throughout both systems. Table 31-9 does not show the increase in ancillary service production, which would serve to increase system reliability. The overall effect of Alternative B would be a somewhat reduced effect on total power and energy use, when compared with Alternative A. Regarding generation, because of the increased Sites Pumping/Generating Plant generating capacity due to higher Sites Reservoir level (121 MW for Alternative B versus 107 MW for Alternative A) offset by the lack of the Delevan Pipeline powerhouse (0 MW for Alternative B versus 10.8 MW for Alternative A), Alternative B would result in a small increase in renewable generating capacity (3.2 MW ) when compared to Alternative A. Because the adverse impacts on power production and energy use associated with Alternative B would be less than for Alternative A, and the benefits offered would be equal to or greater than for Alternative A, impacts to power production and energy use in the Extended Study Area for Alternative B would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative**.**

**Table 31-9**
**CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative B**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | Alternative B | Alternative B minus Existing Conditions | Alternative B minus No Project/No Action Alternative |
|---|---|---|---|---|---|---|
| **CVP Facilities** | | | | | | |
| Energy Generation | Long-Term[b] | 4,712 | 4,701 | 4,718 | 6 | 18 |
| | Dry and Critical[c] | 3,533 | 3,513 | 3,506 | -27 | -6 |
| Energy Use | Long-Term | 1,124 | 1,116 | 1,147 | 23 | 32 |
| | Dry and Critical | 894 | 878 | 902 | 8 | 25 |
| Net Generation[d] | Long-Term | 3,588 | 3,585 | 3,571 | -17 | -14 |
| | Dry and Critical | 2,639 | 2,635 | 2,604 | -35 | -31 |
| **SWP Facilities** | | | | | | |
| Energy Generation | Long-Term | 4,326 | 4,386 | 4,493 | 167 | 107 |
| | Dry and Critical | 3,033 | 2,909 | 3,128 | 96 | 220 |
| Energy Use | Long-Term | 7,848 | 8,088 | 8,464 | 616 | 376 |
| | Dry and Critical | 6,354 | 6,013 | 6,727 | 373 | 714 |
| Net Generation | Long-Term | -3,522 | -3,702 | -3,971 | -449 | -269 |
| | Dry and Critical | -3,321 | -3,104 | -3,599 | -277 | -494 |
| **Proposed Project Facilities[d]** | | | | | | |
| Energy Generation | Long-Term | 0 | 0 | 104 | 104 | 104 |
| | Dry and Critical | 0 | 0 | 100 | 100 | 100 |
| Energy Use | Long-Term | 13 | 13 | 195 | 183 | 182 |
| | Dry and Critical | 11 | 12 | 106 | 95 | 95 |
| Net Generation | Long-Term | -13 | -13 | -91 | -79 | -78 |
| | Dry and Critical | -11 | -12 | -6 | 5 | 6 |
| **All Facilities (CVP, SWP and Proposed Project)[e]** | | | | | | |
| Energy Generation | Long-Term | 9,038 | 9,087 | 9,316 | 277 | 229 |
| | Dry and Critical | 6,566 | 6,422 | 6,735 | 170 | 313 |
| Energy Use | Long-Term | 8,983 | 9,214 | 9,801 | 818 | 587 |
| | Dry and Critical | 7,257 | 6,901 | 7,732 | 474 | 830 |
| Net Generation | Long-Term | 51 | -132 | -498 | -548 | -366 |
| | Dry and Critical | -694 | -482 | -1,004 | -310 | -522 |

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

[b]Long-Term is the average quantity for the calendar years 1922-2002.

[c]Dry and Critical is the average quantity for Dry and Critical years according to the Sacramento River 40-30-30 index.

[d]Proposed Project Facilities include Tehama-Colusa Canal and Glenn-Colusa Irrigation District Canal pumping facilities.

[e]Energy Use and Net Generation for all facilities does not equal sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant (RBPP) is included in both CVP and Project facilities. Results for RBPP from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.

Notes:

CVP = Central Valley Project
GWh = gigawatt-hours
SWP = State Water Project

#### *Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy*

Alternative B would not likely decrease per capita energy consumption in the Extended Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Therefore, Alternative B is expected to promote the use of renewable energy, and would not cause a reduction in generation of renewable energy. Therefore, operation of Alternative B would result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### *31.3.8.2 Secondary Study Area – Alternative B*

### *Construction, Operation, Maintenance, and Recreation Use Impacts*

#### *Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities*

The impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Secondary Study Area.

#### *Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities*

Impacts on power production and energy use associated with Alternative B would be less than that for Alternative A. Alternative B would have approximately the same effect on overall energy generation and consumption as Existing Conditions and the No Project/No Action Alternative, but would offer the benefit of additional renewable generation, and services to better integrate other sources of renewable energy into the grid. Impacts to power production and energy use in the Secondary Study Area for Alternative B would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

#### *Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy*

Similar to Alternative A, Alternative B would not likely decrease per capita energy consumption in the Secondary Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Operation of Alternative B would, therefore, result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### *31.3.8.3 Primary Study Area – Alternative B*

### *Construction, Operation, Maintenance, and Recreation Use Impacts*

#### *Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities*

The impacts associated with Alternative B as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Primary Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

Alternative B would include a larger Sites Reservoir than Alternative A, allowing an increase in Sites Pumping/Generating Plant capacity to 121 MW, but also an increase in pumping demand of 181.35 MW. Power generation at the TRR, and pumping mode at the Sites and TRR pumping/generating plants, would be the same as described for Alternative A, but the Delevan Pipeline Discharge Facility would be a release-only facility with no pumping or power generation capabilities. Adverse effects on power production and energy use in the Primary Study Area for Alternative B would be reduced, when compared to Alternative A because Alternative B would have more ability to integrate renewable energy into the grid, and benefits would be greater than Alternative A due it its potential to offset fossil fuel generation during times of peak demand. Alternative B would have approximately the same effect on overall energy generation and consumption as Existing Conditions and the No Project/No Action Alternative, but would offer the benefit of additional renewable generation, and services to better integrate other sources of renewable energy into the grid. Therefore, with effective planning efforts for transmission system and power generation capacity additions accounting for the future effects of Project operations, impacts to power or energy use from implementation of Alternative B, when compared to Existing Conditions and the No Project/No Action Alternative would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Alternative B would not likely decrease per capita energy consumption in the Primary Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Operation of Alternative B would, therefore, result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

## 31.3.9 Impacts Associated with Alternative C

### *31.3.9.1 Extended Study Area – Alternative C*

#### *Construction, Operation, Maintenance, and Recreation Use Impacts*

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

The impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Extended Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

When compared to Existing Conditions, Alternative C would result in a net increase in maximum demand of approximately 276 MW for Project pumping power, and a net increase in maximum generating capacity of 141.6 MW. When compared to the No Project/No Action Alternative, the net change in demand and generation in the Extended Study Area caused by development of Alternative C would likely be approximately the same, based on normal load growth and the processes in place to ensure sufficient water supply and electric power generation and transmission capacity remain in place to meet reliability standards.

From a power production and energy use perspective, Alternative C would increase electricity demand by approximately 23 MW when compared to Alternative A (an 8.5 percent increase), and would increase generating capacity by approximately 10 MW when compared to Alternative B (an 8 percent increase). Alternative C would, therefore, offer comparable potential for adverse impact on power demand and energy use when compared to Alternative A. It would also offer the same level of benefit to the system due it its similar generating capacity. Maximum electricity demand for Alternative C pumping would equal approximately 0.19 percent of the total 2009 electric demand in the western U.S. and Canada (compared to 0.17 percent for Alternative A), and would reduce the generation reserve margin by that amount during maximum pumping operations. Alternative C pumping load would be approximately 0.16 percent of total load in the region in 2019 (identical to Alternative A). When operated at maximum generating capacity, Alternative C would add approximately 0.07 percent to the 2009 generation reserve; it would add approximately 0.06 percent in 2014, and 0.06 percent in 2019 (all identical to Alternative A).

As shown in Table 31-10, modeling showed that the addition of Alternative C to the CVP and SWP would cause a net increase in energy use of 594 GWh by CVP and SWP facilities, when compared to Existing Conditions, and a net increase in energy use of 411 GWh by CVP and SWP facilities, when compared to the No Project/No Action Alternative. Table 31-10 does not show the increase in ancillary service production, which would serve to increase system reliability. When compared to 2009 total electrical energy use of 858,793 GWh in the Extended Study Area (Western Interconnection), and projected 2019 energy use of more than 1 million GWh, the increased energy use that would result from Alternative C in 2025 would be 0.05 and 0.04 percent, respectively, of the 2009 actual energy use and 2019 projected electrical energy use in the Extended Study Area (identical to Alternative A). Project-related energy use associated with Alternative C is not expected to be inefficient, wasteful, or unnecessary because it would be used to store water and potential electric energy for later use when needed and would therefore result in a **less-than-significant impact**, when compared to Existing Conditions and the No Project/No Action Alternative.

**Table 31-10**
**CVP,SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative C**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | Alternative C | Alternative C minus Existing Conditions | Alternative C minus No Project/No Action Alternative |
|---|---|---|---|---|---|---|
| **CVP Facilities** | | | | | | |
| Energy Generation | Long-Term[b] | 4,712 | 4,701 | 4,715 | 3 | 14 |
| | Dry and Critical[c] | 3,533 | 3,513 | 3,479 | -54 | -34 |
| Energy Use | Long-Term | 1,124 | 1,116 | 1,155 | 31 | 40 |
| | Dry and Critical | 894 | 878 | 901 | 8 | 24 |
| Net Generation[d] | Long-Term | 3,588 | 3,585 | 3,559 | -28 | -26 |
| | Dry and Critical | 2,639 | 2,635 | 2,578 | -62 | -58 |

**Table 31-10**
**CVP, SWP, and Proposed Project Facilities Energy Use (in GWh)[a] – Alternative C**

| Parameter | Long-Term Average or Dry and Critical Water Year Type Average | Existing Conditions | No Project/No Action Alternative | Alternative C | Alternative C minus Existing Conditions | Alternative C minus No Project/No Action Alternative |
|---|---|---|---|---|---|---|
| **SWP Facilities** | | | | | | |
| Energy Generation | Long-Term | 4,326 | 4,386 | 4,496 | 170 | 110 |
| | Dry and Critical | 3,033 | 2,909 | 3,168 | 136 | 259 |
| Energy Use | Long-Term | 7,848 | 8,088 | 8,473 | 625 | 385 |
| | Dry and Critical | 6,354 | 6,013 | 6,848 | 494 | 834 |
| Net Generation | Long-Term | -3,522 | -3,702 | -3,977 | -455 | -275 |
| | Dry and Critical | -3,321 | -3,104 | -3,679 | -358 | -575 |
| **Proposed Project Facilities[d]** | | | | | | |
| Energy Generation | Long-Term | 0 | 0 | 157 | 157 | 0 |
| | Dry and Critical | 0 | 0 | 173 | 173 | 0 |
| Energy Use | Long-Term | 13 | 13 | 278 | 265 | 13 |
| | Dry and Critical | 11 | 12 | 199 | 188 | 11 |
| Net Generation | Long-Term | -13 | -13 | -121 | -108 | -13 |
| | Dry and Critical | -11 | -12 | -26 | -15 | -11 |
| **All Facilities (CVP, SWP and Proposed Project)[e]** | | | | | | |
| Energy Generation | Long-Term | 9,038 | 9,087 | 9,368 | 329 | 281 |
| | Dry and Critical | 6,566 | 6,422 | 6,821 | 255 | 399 |
| Energy Use | Long-Term | 8,983 | 9,214 | 9,901 | 918 | 687 |
| | Dry and Critical | 7,257 | 6,901 | 7,945 | 687 | 1,044 |
| Net Generation | Long-Term | 51 | -132 | -543 | -594 | -411 |
| | Dry and Critical | -694 | -482 | -1,131 | -437 | -649 |

[a]Results are estimated using LTGEN, SWP_Power, and NODOS_Power using data from the CALSIM II model.
[b]Long-Term is the average quantity for the calendar years 1922-2002.
[c]Dry and Critical is the average quantity for Dry and Critical years according to the Sacramento River 40-30-30 index.
[d]Proposed Project Facilities include Tehama-Colusa Canal and Glenn-Colusa Irrigation District Canal pumping facilities.
[e]Energy Use and Net Generation for all facilities does not equal sum of Energy Use and Net Generation for CVP, SWP, and Project facilities because energy use at Red Bluff Pumping Plant (RBPP) is included in both CVP and Project facilities. Results for RBPP from LTGEN are subtracted from Energy Use and Net Generation for all facilities to avoid double-counting.
Notes:
CVP = Central Valley Project
GWh = gigawatt-hours
SWP = State Water Project

### *Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy*

Similar to Alternative A, Alternative C would not likely decrease per capita energy consumption in the Extended Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. The increased energy use resulting from the additional water storage available from Alternative C to CVP or SWP customers, when compared to Existing Conditions and the No Project/No Action Alternative, would displace energy use associated with other water sources, perhaps leading to a net reduction in water-related energy use in the Extended Study Area. Operation of Alternative C is, therefore, expected to result in a **less-than-significant impact** to power and energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### *31.3.9.2 Secondary Study Area – Alternative C*

#### *Construction, Operation, Maintenance, and Recreation Use Impacts*

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

The impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Secondary Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

Maximum electric demand for pumping if Alternative C is implemented would equal approximately 0.47 percent of the total 2009 electric demand in California, and would reduce the generation reserve margin by that amount in the state during maximum pumping operations. Alternative C pumping demand would be approximately 0.45 percent of total demand in 2014 in the Secondary Study Area, and 0.43 percent of total demand in 2019, compared to 0.41 percent and 0.36 percent, respectively, for Alternative A. When operated at maximum generating capacity, Alternative C would add approximately 0.19 percent to the 2009 generation reserve in the same region, compared to 0.17 percent for Alternative A. The modeling projection of a 411 GWh increase in energy use by CVP and SWP facilities, when compared to the No Project/No Action Alternative, would be 0.29 percent of the 2009 total electrical energy use of 124,405 GWh, and 0.26 percent of the 2019 energy use of 140,378 GWh, in the Primary Study Area (northern California). This increased energy use caused by Alternative C in 2025 would be 0.14 percent of the 2009 total Secondary Study Area electrical energy use of 285,913 GWh, and 0.13 percent of the projected 2019 energy use of 321,649 GWh.

By making up to 1.81 MAF of additional storage available for the water system, water releases from Alternative C would lead to increased use of energy for pumping the released water as far as Southern California. Energy use associated with Alternative C would not be inefficient, wasteful, or unnecessary because it would be used to store water and potential electric energy for later use when needed. Impacts to power and energy caused by operation of Alternative C would, therefore, be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Similar to Alternative A, Alternative C would not likely decrease per capita energy consumption in the Secondary Study Area, but would promote increased reliance on renewable resources and decreased reliance on fossil fuels due to its ability to assist integration of variable renewable power resources, such as wind and solar. Operation of Alternative C would, therefore, result in a **less-than-significant impact** to power or energy use, when compared to Existing Conditions and the No Project/No Action Alternative.

### 31.3.9.3 Primary Study Area – Alternative C

#### Construction, Maintenance, and Recreation Use Impacts

***Impact Power-1: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Construction, Maintenance, and Recreation Activities***

The impacts associated with Alternative C as they relate to inefficient, wasteful, or unnecessary consumption of energy during construction, maintenance, and recreation activities would be the same as described for Alternative A for the Primary Study Area.

***Impact Power-2: Inefficient, Wasteful, or Unnecessary Consumption of Energy during Operational Activities***

For Alternative C, the Sites Pumping/Generating Plant would use up to 181.4 MW in pumping mode, and would generate up to 121 MW; the TRR Pumping/Generating Plant would use up to 19.68 MW in pumping mode, and generate up to 9.8 MW; and the Delevan Pipeline Intake Facilities would use up to 65.5 MW in pumping mode, and generate up to 10.8 MW. Maximum electricity demand for Alternative C (276 MW) would equal approximately 1.1 percent of the total 2009 electric demand in northern California, and would reduce the generation reserve margin by that amount in the State during maximum pumping operations. Alternative C pumping demand would be approximately 1.04 percent of total 2014 demand in the region, and 1.0 percent of total 2019 demand. When operated at maximum generating capacity, Alternative C would add approximately 0.46 percent to the 2009 generation reserve; it would add a projected 0.36 percent of total northern California generation capacity in 2014, and 0.37 percent in 2019. The modeling projection of a 265 GWh increase in energy use by CVP and SWP facilities, when compared to Existing Conditions and the No Project/No Action Alternative, would be 0.21 percent of the 2009 total electrical energy use of 124,405 GWh, and 0.19 percent of the 2019 energy use of 140,378 GWh, in the Primary Study Area (northern California). The overall effect on power and energy use by Alternative C is, therefore, nearly identical to that of Alternative A, including beneficial effects. Project-related energy use associated with Alternative C is not expected to be inefficient, wasteful, or unnecessary because it would be used to store water and potential electric energy for later use when needed and would therefore result in a **less-than-significant impact**, when compared to Existing Conditions and the No Project/No Action Alternative.

***Impact Power-3: A Substantial Reduction in the Generation of Renewable Energy***

Similar to Alternative A, this net increase in demand would likely be accommodated by proper power planning studies, especially given the projected large generation margins in the region.

Alternative C operations could increase the reliability of the grid both by curtailing power use for pumping (up to 276 MW in essentially instantaneous reduction for Alternative C), and by ramping up power production (up to 141.6 MW). This ability will also assist in integrating renewable energy generation into the grid as utilities increase purchases of renewable energy to meet RPS requirements. Alternative C water operations also could provide at least a partial offset of pumping energy use if the water released from Alternative C storage displaces a more intensive water source, such as deep groundwater or desalination. Impacts to power and energy use from Alternative C would be **less than significant**, when compared to Existing Conditions and the No Project/No Action Alternative.

## 31.4 Mitigation Measures

With continued effective planning for California transmission grid improvements and generation capacity additions, impacts to power production and energy use associated with operation of the Project would be **less than significant.** Therefore, no mitigation is required or recommended.

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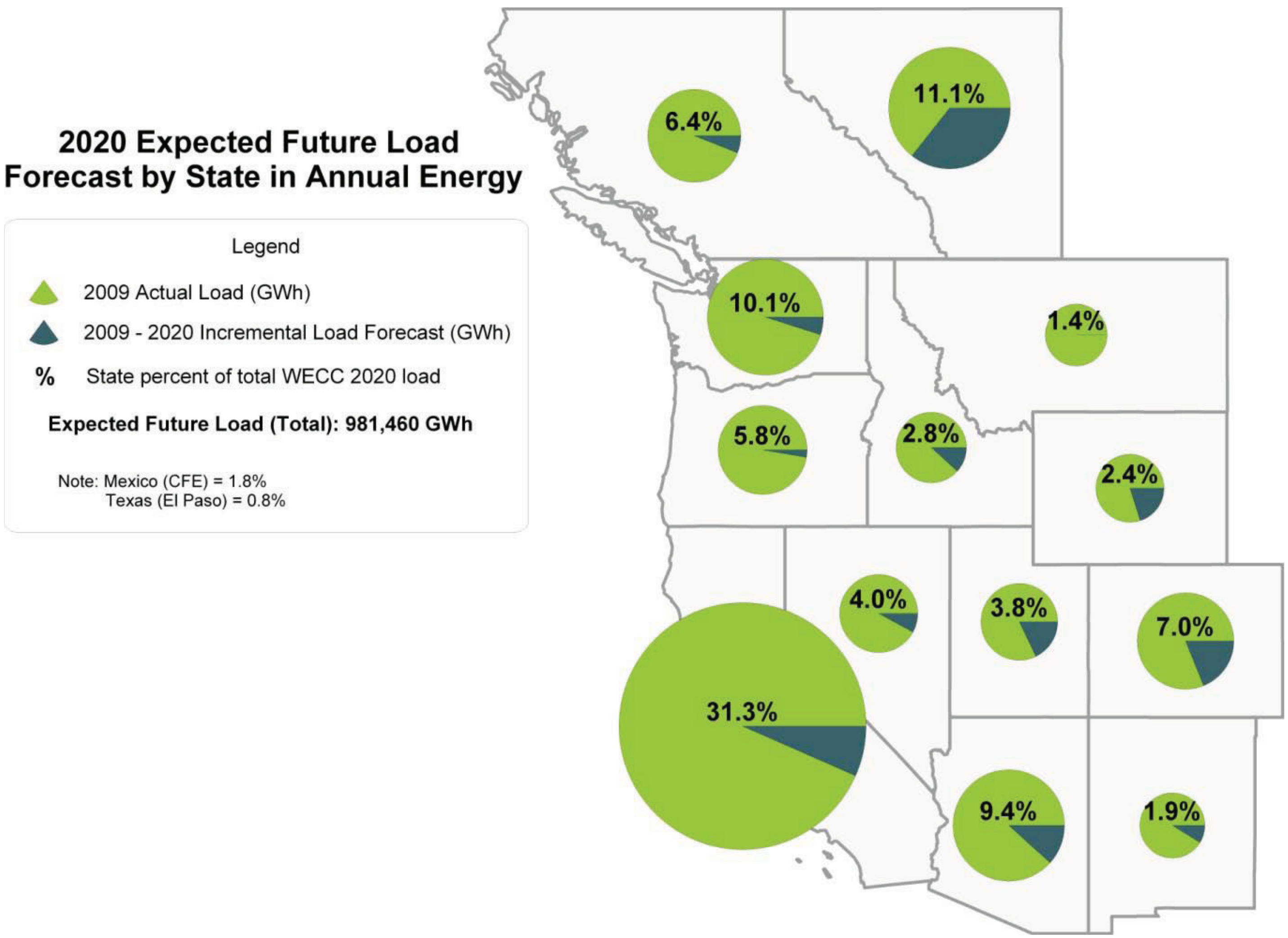
# Figures




Source: WECC

**FIGURE 31-1**
**Western Electric Coordinating Council, Loads by State and Province**
*North-of-the Delta Offstream Storage Project*

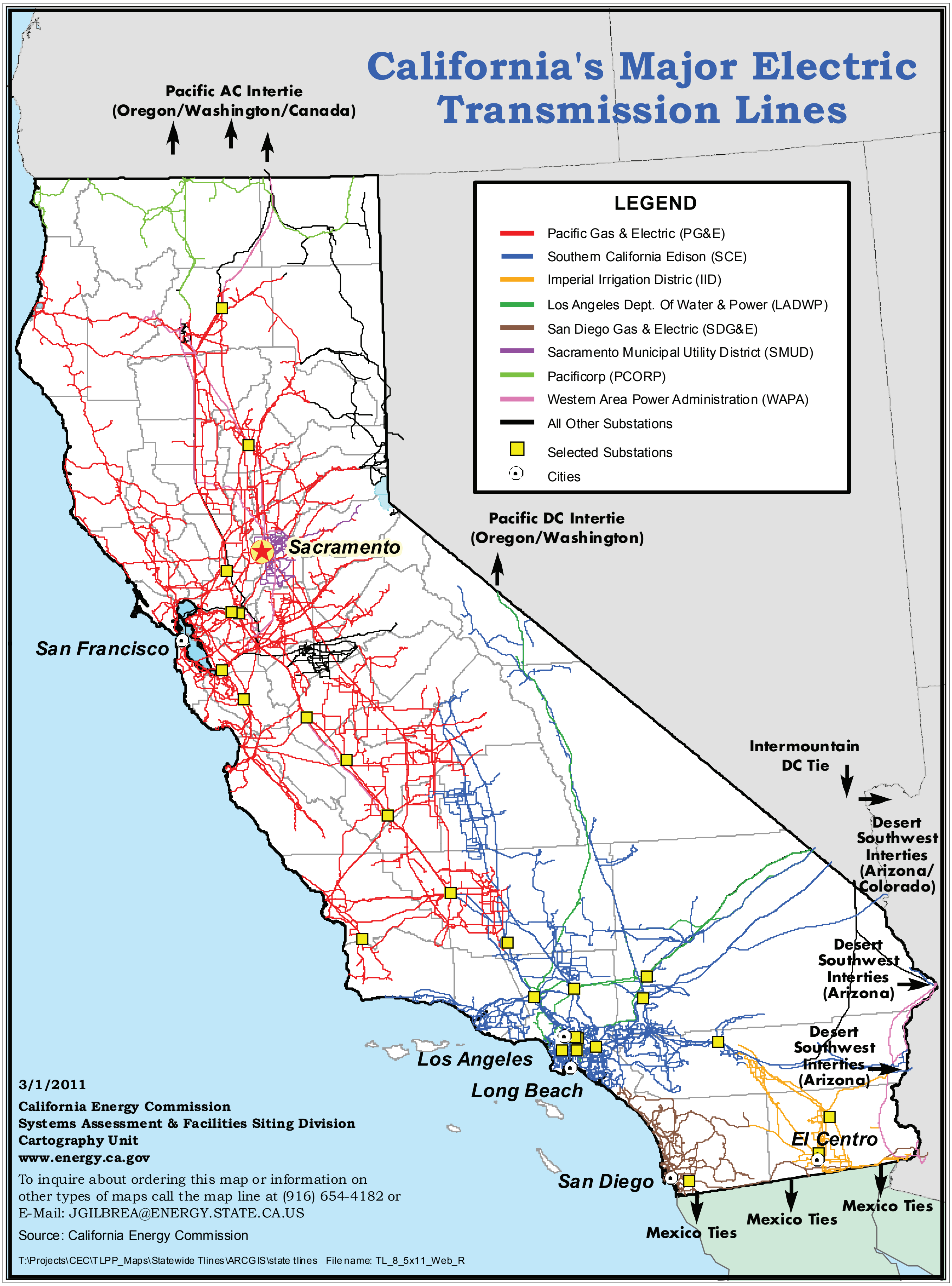



**FIGURE 31-2**
**California Electric Transmission System**
*North-of-the Delta Offstream Storage Project*

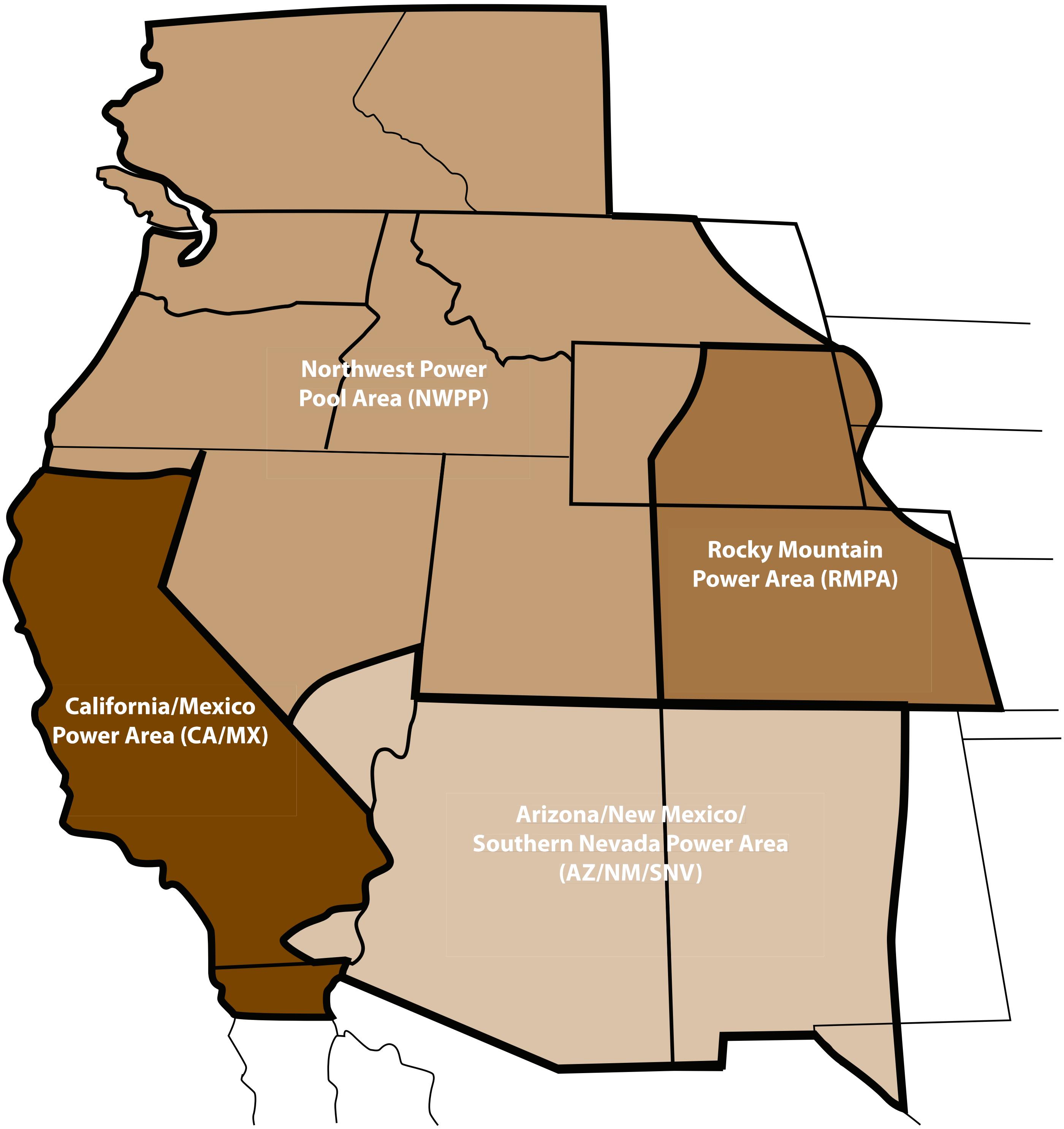
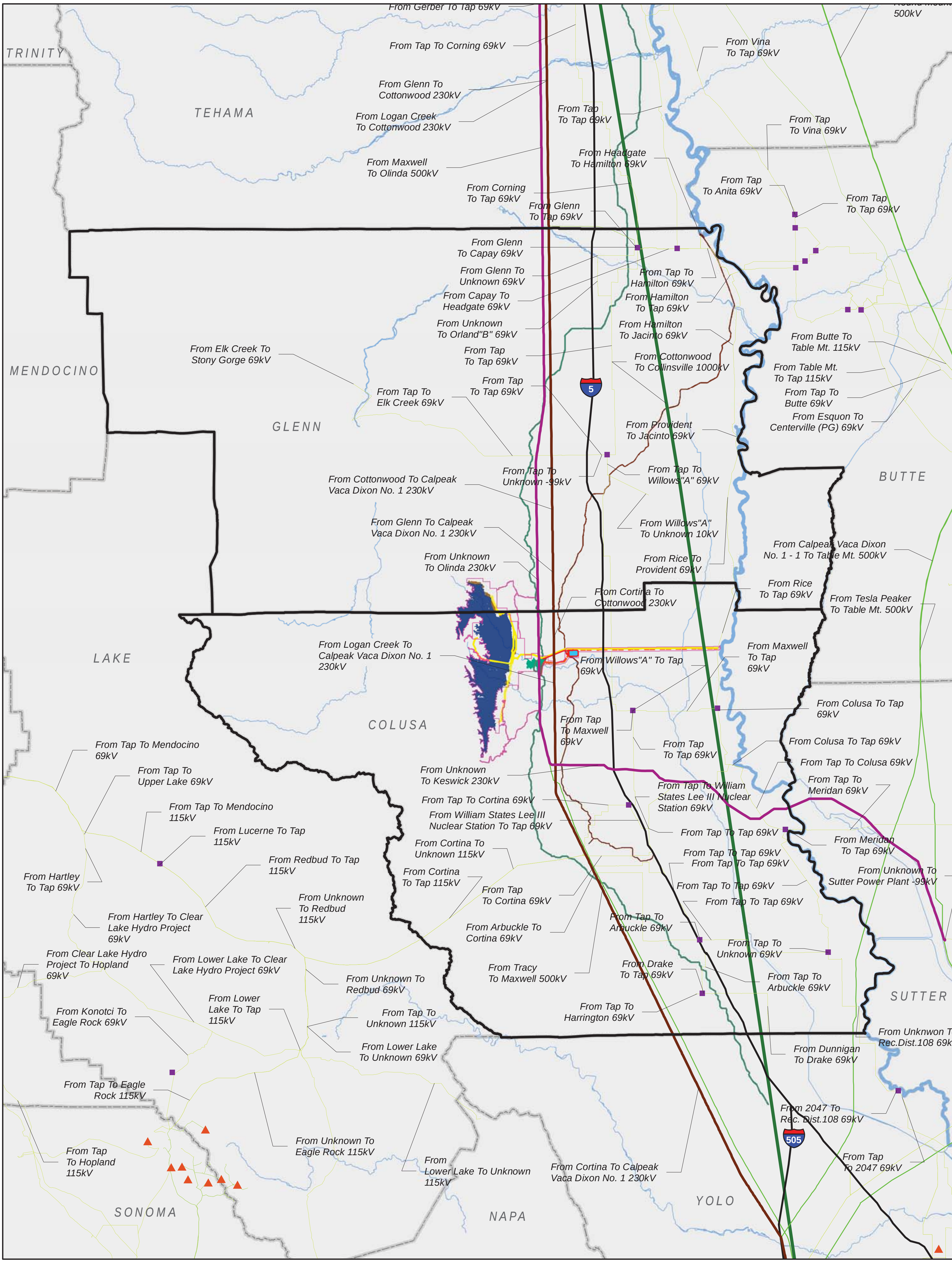



**FIGURE 31-3**
**WECC Reporting Areas**
*North-of-the Delta Offstream Storage Project*

*This document is not released as a draft EIR pursuant to CEQA Guidelines § 15087. As such, DWR is not soliciting and will not respond to comments submitted on this document, although any comments received will be retained and may be considered during preparation of a future draft EIR.*




**Legend**

- Glenn and Colusa Counties
- Substation
- PGE Co. (230-kV)
- WAPA (500-kV)
- Power Generating Facility

**Transmission Lines**

- Below 230kV
- 230kV - 344kV
- 345kV - 499kV
- 500kV - 734kV
- 735kV - 999kV
- AC-DC-AC Tie
- DC

**Project Facilities**

- GCID Pumping/Generating Plant
- Construction Disturbance Area
- Delevan Transmission Line
- Delevan & TRR Pipelines
- Delevan Pipeline Discharge
- Delevan Pipeline Intake/Outlet
- Holthouse Dam
- Dams
- GCID Canal
- T-C Canal
- TRR Pumping/Generating Plant
- TRR
- Funks/Holthouse Reservoir
- Sites Reservoir
- Sacramento River
- Rivers and Streams

SOURCE: Existing Transmission Line Data, Platts Data 2010.

**FIGURE 31-4**
**Transmission Lines in Glenn and Colusa Counties Relative to Project Facilities**
*North-of-the-Delta Offstream Storage Project*

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