Appendix J

Hydropower and Electric Grid Analysis of Lower San Joaquin River Flow Alternatives

Appendix J

Hydropower and Electric Grid Analysis of Lower San Joaquin River Flow Alternatives

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J.1 Introduction

This appendix provides estimates of the potential effects on hydropower generation and electric grid reliability in the Lower San Joaquin River (LSJR) watershed caused by implementing the LSJR alternatives. The LSJR alternatives propose to alter the February– June flow on the Stanislaus, Tuolumne, and Merced Rivers (three eastside tributaries), which could affect reservoir operations and surface water diversions and the associated timing and amount of hydropower generation from the LSJR watershed.

This analysis relies on the State Water Resources Control Board's (State Water Board's) water supply effects (WSE) model to estimate the effects of the LSJR alternatives on reservoir releases and storage (elevations head) and allowable diversions to off-stream generation facilities, and then calculates the associated change in monthly and annual amounts of energy produced. This output then provides input to electric grid reliability modeling, which evaluates the potential for these changes to effect electric grid reliability under peak load and outage contingency scenarios.

There are three different LSJR alternatives, each consisting of a specified percentage of unimpaired flow requirement for the Stanislaus, Tuolumne, and Merced Rivers. For a particular alternative, each tributary must meet the specified percentage of its own unimpaired flow at its mouth with the LSJR during the months of February–June. The percentage unimpaired flow requirements are 20 percent, 40 percent and 60 percent[1], respectively, for LSJR Alternatives 2–4, but only apply when flows are otherwise below a specified trigger level.[2] Also, flows must not drop below specified levels on each tributary, and together must maintain a minimum flow on the San Joaquin River (SJR) at Vernalis. Specific trigger and minimum flow levels and other details of the LSJR alternatives are presented in Chapter 3 *Alternatives Description*, Section 3.2, of this Substitute Environmental Document (SED), and are the basis for how the alternatives are modeled in this appendix.

Numerous hydropower generation facilities on the three eastside tributaries are evaluated in this analysis. The major facilities potentially affected, however, are those associated with the New Melones Reservoir (New Melones Dam) on the Stanislaus River,[3] New Don Pedro Reservoir (New Don Pedro Dam) on the Tuolumne River, and Lake McClure (New Exchequer Dam) on the Merced River. Figure J-1 shows the location of these and other hydropower facilities in and around the LSJR watershed.

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[1] Any reference in this appendix to 20% unimpaired, 40% unimpaired, and 60% unimpaired is the same as LSJR Alternative 2, LSJR Alternative 3, and LSJR Alternative 4, respectively. Any reference to 1.0 EC objective and 1.4 EC objective is the same as southern Delta water quality (SDWQ) Alternative 2 and SDWQ Alternative 3, respectively.

[2] The minimum percent unimpaired flow requirement on a tributary for a particular alternative would not apply once flows in the river or downstream are at a level of concern for flooding or public safety. As described in the program of implementation for the flow objectives, such levels will be coordinated by the State Water Board with the appropriate federal, state, and local agencies. The description of the WSE modeling in Appendix F.1, *Hydrologic and Water Quality Modeling*, describes the river flow levels above which the minimum unimpaired flow requirements were assumed to no longer apply.

[3] The Tulloch reservoir and hydro power plant on the Stanislaus River could also be affected by the project. However, this is a relatively small facility, rated at 18 MW. Therefore, any impact associated with a reduction in its capacity on the California interconnected grid is likely to be minimal.

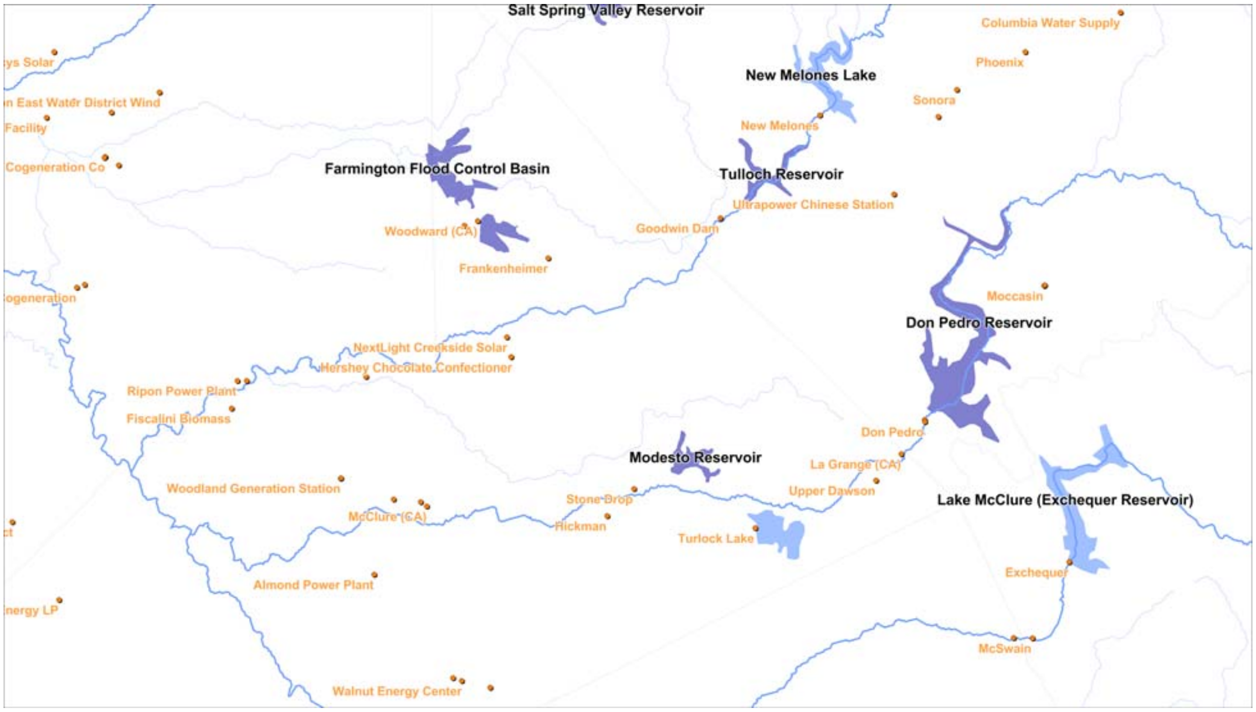


Figure J-1. Location of Hydropower Facilities in the LSJR Watershed (Source: Ventyx)

J.2 Energy Generation Effects

The analysis in this section estimates the timing and amount of energy in gigawatt hours (GWh) generated by hydropower facilities on the eastside tributaries for the different LSJR alternatives and compares them against baseline. The timing and amounts of energy generated are calculated from the timing, rates of release, and elevation head of reservoirs at in-stream hydropower facilities and allowable diversions to off-stream facilities, estimated across 82 years of hydrology by the WSE model for the LSJR Alternatives and by DWR's CALSIM Water Resources Simulation Model (CALSIMII) for baseline. The average annual energy generation and the distribution of average monthly energy generation across these 82 years of hydrology for each LSJR alternative are then compared to those for baseline.

J.2.1 Methodology

For each of the LSJR alternatives, this analysis estimates the amount of energy (GWh) that would be generated on an annual or monthly basis from the various facilities on the eastside tributaries for comparison against the amount generated under baseline conditions. Baseline conditions (baseline) are those from the "Current (2009) Conditions" CALSIM II model run from the California Department of Water Resource's *State Water Project Reliability Report 2009*.

Hydropower facilities on the eastside tributaries were grouped into four categories for this analysis, based on where they are located relative to the three major tributary dams and whether they are in-stream facilities or off-stream. Table J-1 contains a list of the hydropower facilities on the LSJR grouped into these categories, along with some basic facility information.

Energy generated from in-stream facilities is estimated by inputting reservoir head and release rates obtained from the WSE model (for the LSJR alternatives) and CALSIMII model (for baseline) into the power equation presented below. As described in Appendix C, *Technical Report On The Scientific Basis For Alternative San Joaquin River Flow And Southern Delta Salinity Objectives,* the WSE model provides estimates of reservoir operations and allowable surface water diversions associated with the different LSJR alternatives. For simulation of LSJR Alternatives 2–4, the WSE model used diversion delivery rule (cutback) curves developed to match end-of-September (carryover) storage from the baseline CALSIM model run as closely as possible. Special attention was given to not exceeding the number of times reservoir storage dropped below set minimum levels of 300 thousand acre-feet (TAF), 500 TAF, and 200 TAF for New Melones, New Don Pedro, and Lake McClure, respectively. If different diversion delivery rule curves are used to model the LSJR alternatives, resulting reservoir storage levels and release rates, and associated amounts and timing of hydropower generated would also be different.

The monthly energy generated from facilities at the major dams, or facilities in-stream and downstream of the major dams, was calculated using the following power equation on a monthly time step:

$$HP = \left(e_p \gamma Q h_g\right) \div 550 \qquad \textit{(Eqn. J-1)}$$

where HP is the total horsepower generated by the facility, e_p is the power plant efficiency, (80 percent in all facilities), γ is weight of water, Q is the flow released from the reservoir and through the turbines, and h_g is the elevation head behind the dam. The reservoir release rates (Q) and reservoir elevations (h_g) are obtained from the WSE model output for LSJR Alternatives 2–4 and from CALSIM for the baseline. All hydropower facilities were assumed to operate within the constraints of the facility; spills causing flows greater than capacity do not produce energy above the maximum capacity. In-stream facilities located downstream of the major dams were assumed to have constant h_g equal to the maximum head of the reservoir as these facilities are generally run-of-the-river. Horsepower obtained from the above equation is then converted to megawatts and multiplied by the number of hours in the month to provide the total energy generated in GWh for that month. Annual energy estimates are the sum of the associated monthly estimates.

An off-stream facility is one supplied by diversions of surface water from the associated river. Energy generated from off-stream facilities for each LSJR alternative was estimated using the following equation to determine the effect of that alternative compared to the baseline on a monthly basis:

ΔPower = (TotD(alternative) – TotD(baseline)) / TotD(baseline) x Nameplate Capacity *(Eqn. J-2)*

where the *ΔPower* is calculated in megawatts (MW), *TotD* is the allowable surface water diversion from the WSE model for the associated tributary (for the respective alternative and baseline), and the nameplate capacity is the maximum generating capacity of the power facility. The amount of power produced in these facilities under baseline is assumed to be the nameplate capacity. This is a simplifying and conservative assumption for facilities that represent a relatively small portion of the overall generating capacity in their respective watersheds (1.0 percent on the Stanislaus, 0.7 percent on the Tuolumne, and 4.8 percent on the Merced as shown in Table J-1). The power calculated by this equation is then multiplied by the number of hours in the month to provide the total amount of energy in GWh generated for that month. Annual energy estimates are the sum of the associated monthly estimates.

Hydropower generated from facilities on reservoirs upstream of the major dams on the Stanislaus and Tuolumne Rivers is assumed to be unaffected by the LSJR alternatives. The storage capacity of these upstream reservoirs, as needed to shift flows between spring and summer months, is limited and much less than such capacity available downstream in the major reservoirs. The Merced River has no major hydropower reservoirs upstream of Lake McClure (New Exchequer Dam).

Table J-1. List of Hydropower Facilities in the LSJR Watershed (CEC 2012).

River Basin	Hydro-electric Power Plant Name	Nameplate Capacity (MW)	% of Power Capacity in Basin	Location Relative to Rim Dam
Stanislaus	Woodward	2.85	0.4	Offline
	Frankenheimer	5.04	0.6	Offline
	Tulloch	17.10	2.2	Inline
	Angels	1.40	0.2	Upstream
	Phoenix	1.60	0.2	Upstream
	Murphys	4.50	0.6	Upstream
	New Spicer	6.00	0.8	Upstream
	Spring Gap	6.00	0.8	Upstream
	Beardsley	9.99	1.3	Upstream
	Sand Bar	16.20	2.1	Upstream
	Donnells-Curtis	72.00	9.2	Upstream
	Stanislaus	91.00	11.6	Upstream
	Collierville Ph	249.10	31.8	Upstream
	New Melones	300.00	38.3	Rim Dam
	Upstream Capacity	457.79	58.5	NA
	Affected Capacity	324.99	41.5	NA
Tuolumne	Stone Drop	0.20	0.0	Offline
	Hickman	1.08	0.2	Offline
	Turlock Lake	3.30	0.5	Offline
	La Grange	4.20	0.7	Inline
	Upper Dawson	4.40	0.7	Upstream
	Moccasin Lowhead	2.90	0.5	Upstream
	Moccasin	100.00	16.6	Upstream
	R C Kirkwood	118.22	19.6	Upstream
	Dion R. Holm	165.00	27.4	Upstream
	Don Pedro	203.00	33.7	Rim Dam
	Upstream Capacity	390.52	64.8	NA
	Affected Capacity	211.78	35.2	NA
Merced	Fairfield	0.90	0.8	Offline
	Reta - Canal Creek	0.90	0.8	Offline
	Merced ID – Parker	3.75	3.2	Offline
	Mcswain	9.00	7.6	Inline
	Merced Falls	9.99	8.4	Inline
	New Exchequer	94.50	79.4	Rim Dam
	Upstream Capacity	0.00	0.0	NA
	Affected Capacity	119.04	100%	NA

J.2.2 Results

Table J-2 contains a summary of the average annual change in total energy generation (GWh) on each of the tributaries due to the alternatives. Generally, as the percent of unimpaired flow alternative increases, the amount of energy generated annually is slightly reduced. These changes are also represented as a percent of baseline energy generation in Table J-3. .

The pattern of total monthly energy generation (over 82 years of simulation) from the entire LSJR watershed for the LSJR alternatives and baseline are presented in Figure J-2a and the associated average changes in monthly energy generation are presented in Figure J-2b. These figures show a general increase in energy being produced in May and June, as more flow (i.e., reservoir releases) is being provided in those months by the LSJR alternatives when compared to baseline. The decrease during July and August is due to a corresponding reduction in reservoir releases during those months. These effects are more pronounced as the percentage of unimpaired flow requirement of the LSJR alternatives increases.

The corresponding relative effect on revenues from hydropower generation will be slightly greater because the price of energy is generally less during February–June than during July and August. An evaluation of the corresponding revenue loss and associated economic effects is evaluated Chapter 18, *Economic Analyses*.

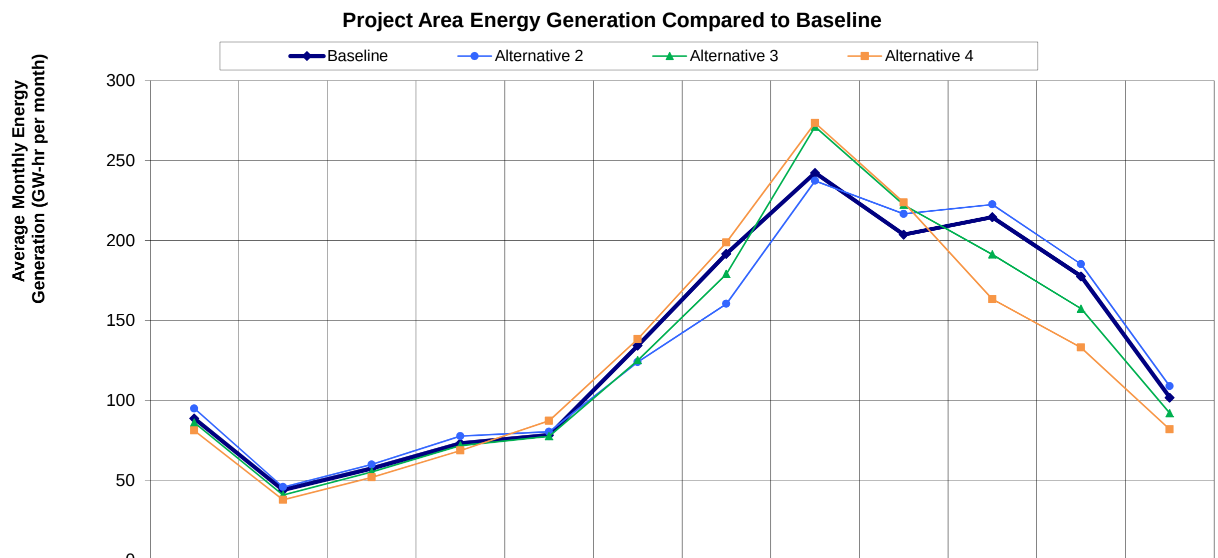
Table J-2. Average Annual Baseline Energy Generation and Difference from Baseline by Tributary (GWh)

Alternative	Stanislaus	Tuolumne	Merced	Plan Area
Baseline	577	628	403	1,607
20% UF	7	-1	0	6
40% UF	-20	-11	-7	-38
60% UF	-33	-19	-16	-68

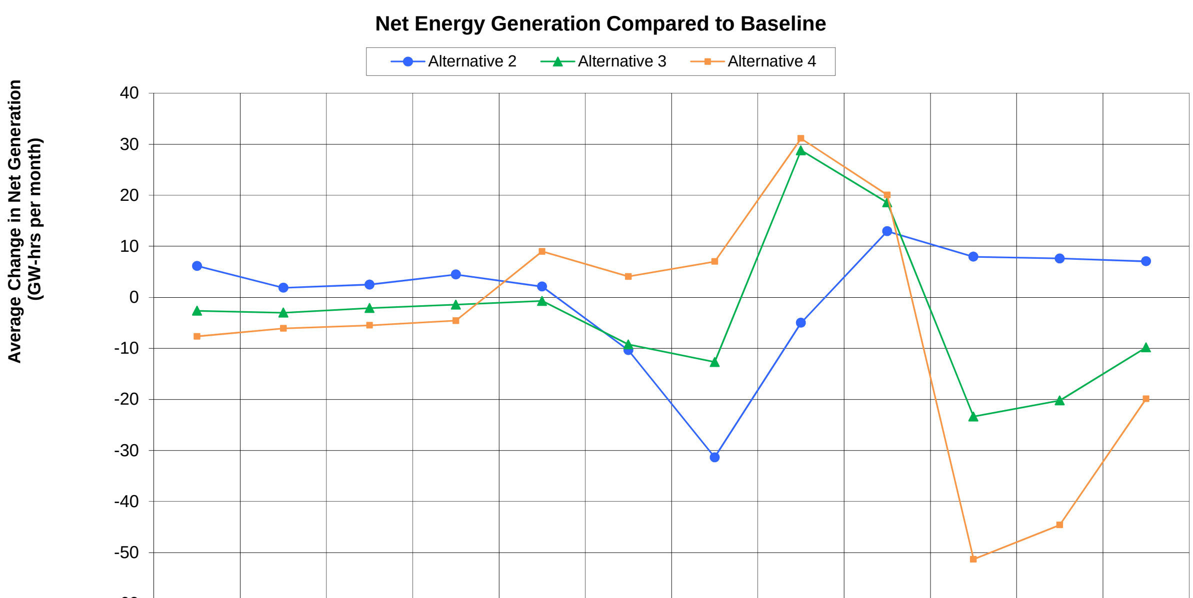
Note: 20% unimpaired flow, 40% unimpaired flow, and 60% unimpaired flow is LSJR Alternative 2, 3, and 4, respectively.
GWh = gigawatt hours
UF = unimpaired flow

Table J-3. Average Annual Energy Generation Difference as Percent Change from Baseline by Tributary (Note: 20% Unimpaired Flow [UF], 40% Unimpaired Flow, and 60% Unimpaired Flow are LSJR Alternative 2, 3, and 4, Respectively).

Alternative	Stanislaus (% dif)	Tuolumne (% dif)	Merced (% dif)	Plan Area (% dif)
Baseline	0%	0%	0%	0%
20% UF	1%	0%	0%	0%
40% UF	-4%	-2%	-2%	-2%
60% UF	-6%	-3%	-4%	-4%



	10	11	12	1	2	3	4	5	6	7	8	9
Baseline	89	44	57	73	78	134	192	242	204	215	178	102
Alternative 2	95	46	60	78	80	124	160	237	217	223	185	109
Alternative 3	86	41	55	72	78	125	179	271	222	191	157	92
Alternative 4	81	38	52	69	87	138	199	273	224	163	133	82



	10	11	12	1	2	3	4	5	6	7	8	9
Alternative 2	6.2	1.9	2.5	4.5	2.1	-10.3	-31.3	-5.0	12.9	7.9	7.6	7.1
Alternative 3	-2.6	-3.0	-2.1	-1.4	-0.7	-9.2	-12.7	28.8	18.6	-23.4	-20.2	-9.8
Alternative 4	-7.7	-6.1	-5.5	-4.6	9.0	4.1	7.0	31.1	20.1	-51.3	-44.6	-19.9

Figure J-2. a) (top) Average (across 82 Years of Simulation) of Total Monthly Energy Generation (GWh = gigawatt hours) from Hydropower Facilities in the Stanislaus, Tuolumne, and Merced River Watersheds; and b) (bottom) the Change in Average (across 82 Years of Simulation) of Total Monthly Energy Generation (GWh) Compared to Baseline.

J.3 Overview of the Transmission System in Central California

The following is a brief overview of the transmission systems and the balancing authorities in which the three hydropower plants, New Melones, New Don Pedro, and New Exchequer are located.[4] The balancing authorities are listed in Table J-4 and discussed in the sections below. This information is discussed to provide context for the capacity reduction calculation and power flow analysis discussed in Section J.4, *Hydropower Generating Capacity and Electric Grid Analysis*.

Table J-4. Balancing Authority of Power Plants Under Study

Power Plant	Balancing Authority
New Exchequer	California Independent System Operator (CAISO)
New Melones	Sacramento Municipal Utility District (SMUD)
New Don Pedro	Turlock Irrigation District (TID—68%) and SMUD—32%

Source: SNL Financial LC. Distributed under license from SNL

Note: Don Pedro Hydro Power Plant is jointly owned by TID and Modesto Irrigation District (MID). SMUD performs the Balancing Authority function for MID's portion of the plant while TID is the balancing authority for its portion.

J.3.1 California Independent System Operator

The California Public Utilities Commission (CPUC) adopted the Resource Adequacy (RA) program in 2004 with the twin objectives of providing sufficient resources to the California Independent System Operators (CAISO) to ensure the safe and reliable operation of the grid in real time; and providing appropriate incentives for the siting and construction of new resources needed for reliability in the future (CPUC 2011). As part of the RA program, each load serving entity (LSE) is required to procure enough resources to meet 100 percent of its total forecast load plus a 15 percent reserve. In addition, each LSE is required to file with CPUC demonstrating procurement of sufficient local RA resources to meet its RA obligations in transmission-constrained local areas. Each year CAISO performs the Local Capacity Technical Study (LCT Study) to identify local capacity requirements within its territory. The results of this study are provided to CPUC for consideration in its RA program. These results are also be used by CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) reliability criteria used in the LCT Study (California Independent System Operator 2010).

The LCT Study identifies the local capacity rrequirement (LCR) under normal and contingency system conditions. The three system conditions under which LCR is evaluated are given below:

- Category A : No Contingencies
- Category B : Loss of a single element (N-1)
- Category C: Category B contingency followed by another Category B contingency but with time between the two to allow operating personnel to make any reasonable and feasible adjustments to the system to prepare for the second Category B contingency.

[4] Entities responsible for maintaining load-generation balance in their area and supporting the frequency of the interconnected system.

For any given area or sub-area, the requirement for Category A, B, and C are compared and the most stringent one will dictate that area's LCR requirement. Figure J-3 shows the 10 LCR areas in CAISO for study year 2012. The New Exchequer hydropower plant lies in the Greater Fresno LCR area. The Greater Fresno LCR area is therefore discussed briefly below.

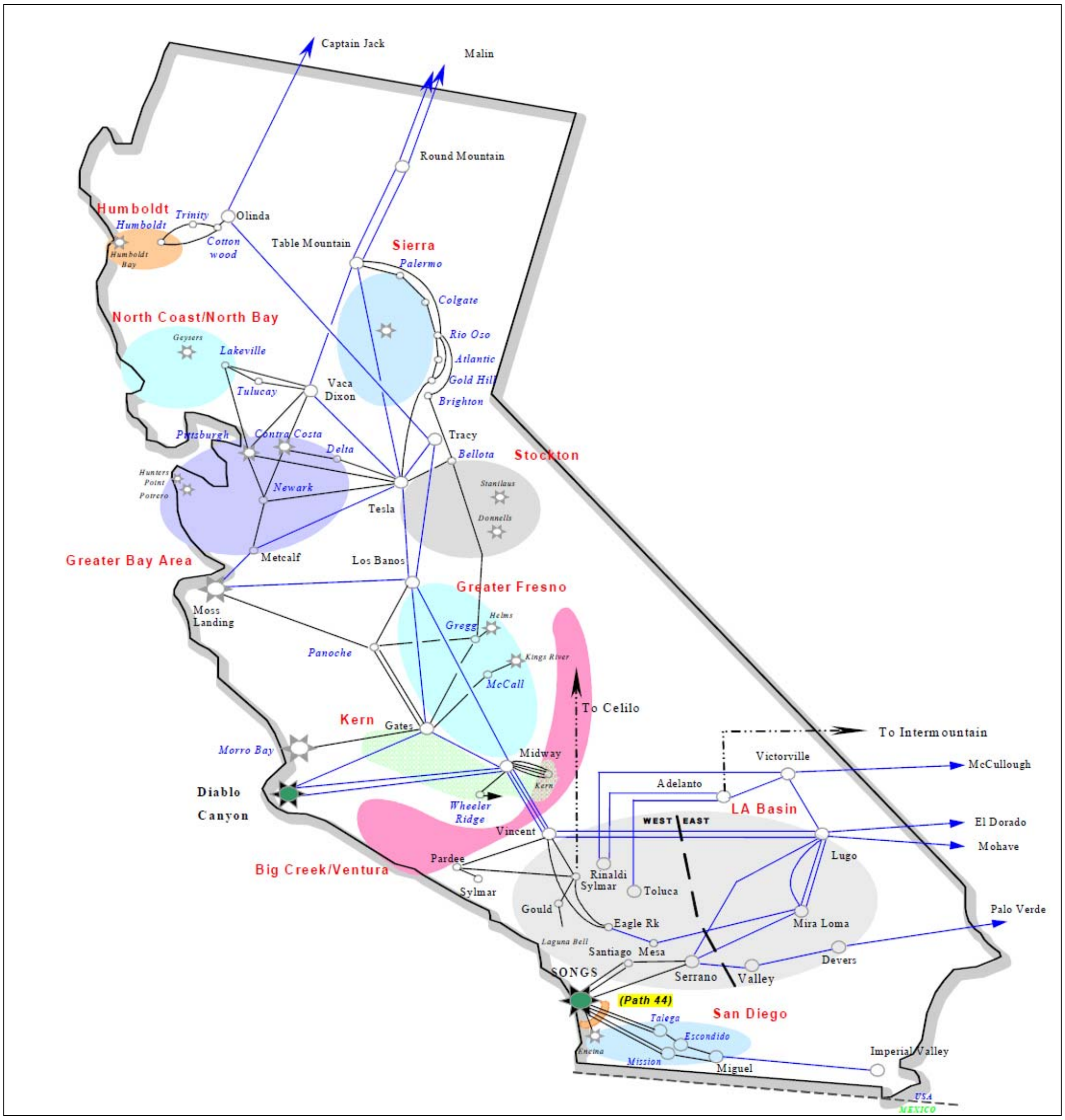


Figure J-3. Local Capacity Area Map of CAISO (Source: CAISO 2010b)

Locational Capacity Requirement in Greater Fresno Area

Table J-5 shows the historical LCR, peak load, and total dependable local area generation for the Greater Fresno area. The exhibit also shows the LCR as a percentage of the total dependable local generation. For example, in 2011, the LCR in Greater Fresno was 2,448 MW while the peak load stood at 3,306 MW; the LCR was 74 percent of the peak load. At the same time, the total dependable generation stood at 2,919 MW which meant that the LCR was 84 percent of the total dependable generation. In other words, in 2011 Greater Fresno had sufficient local resources available to meet its LCR requirements.

Table J-5. Local Capacity Needs vs. Peak Load and Local Area Generation for Greater Fresno Area

Year	LCR (MW)	Peak Load (MW)	LCR as % of Peak Load	Dependable Local Area Generation (MW)	LCR as % of Total Area Generation
2006	2,837	3,117	91	2,651	107
2007	2,219	3,154	70	2,912	76
2008	2,382	3,260	73	2,991	80
2009	2,680	3,381	79	2,829	95
2010	2,640	3,377	78	2,941	90
2011	2,448	3,306	74	2,919	84

Source: Year 2006 to 2011 Local Capacity Technical Analysis, CAISO
MW = megawatts

CAISO also identifies sub-areas within the larger LCR area. It is possible that the sub-areas are resource deficient even though the larger area may have sufficient resources to meet its LCR requirement. For 2011, Greater Fresno LCR area was divided into three sub-areas: Wilson, Herndon, and Henrietta. While Wilson and Herndon had sufficient resources to meet their LCR requirement, Henrietta showed a deficiency of 4 MW under Category C contingency conditions.

The Wilson sub-area largely defined constraints on importing power into Fresno. For year 2011, the most critical contingency was the loss of the Melones-Wilson 230 kilovolt (kV) line concurrent with one of the Helms units out of service. The worst overload under this contingency occurred on the Warnerville-Wilson 230 kV line and established an LCR of 1,997. A number of generation units in the Wilson sub-area were found to be capable of reducing the overload on this line with varying degree of effectiveness. New Exchequer was one of these units.

In 2011, the most critical contingency for the Herndon sub-area was the loss of the Herndon #1 230/115 kV transformer concurrent with Kerckhoff II generator out of service, which established an LCR of 1,132 MW in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

In the Henrietta sub-area, the two most critical contingencies—loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit, and loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV lines—together established a local capacity need of 57 MW in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area. However, under the Category C contingency, the LCR in Henrietta exceeded the total dependable generation by 4 MW for the year 2011, implying that load would need to be shed if the most critical category C contingency were to occur.

Transmission Expansion Plans and New Generator Additions

In the board-approved 2010/2011 transmission plan, CAISO identified a number of transmission upgrades that are needed in the Greater Fresno area to maintain system reliability between 2011 and 2020. PG&E proposed a number of projects to mitigate these reliability violations during the 2010 request window (CAISO 2011). Table J-6 lists the major PG&E projects that were found to be needed by CAISO to maintain system reliability in the Greater Fresno Area.

Table J-6. Reliability Based Transmission Projects in Greater Fresno

Transmission Project Name	Purpose	In-Service Date
Kerckhoff PH #2–Oakhurst 115 kV Line Project	Relieve expected overload on the Corsgold to Oakhurst 115 kV line under 2016–2020 system conditions	2015
Wilson 115 kV Area Reinforcement Project	Relieve a number of reliability violations expected under 2015–2020 system conditions	2015
Oro Loma 70 kV Area Reinforcement Project	Relieve overloads on lines and transformers in the Oro Loma Area under 2015–2020 system conditions	2015

Source: PG&E. 2010
kV = kilovolt

A number of generators are also seeking interconnection in the Greater Fresno Area between now and 2014. Table J-7 provides a list of selected projects that are at an advanced stage of the interconnection process.

Table J-7. Expected New Generator Additions in Greater Fresno

Fuel Type	Interconnecting Sub-Station	Capacity	Expected In-Service Date	County
Natural Gas	Gates Substation 230 kV bus	600	6/1/2014	Kings
Natural Gas	Henrietta Substation 70 kV bus	150	5/31/2013	Kings
Solar	Jacobs Corner Substation 70 kV bus	20	4/2/2012	Kings
Solar	Jacobs Corner Substation 70 kV bus	20	5/1/2012	Kings
Solar	Jacobs Corner Substation 70 kV bus	20	6/1/2012	Kings
Solar	Arco Substation 70 kV bus	20	6/30/2013	Kings
Solar	Corcoran- Kingsburg #1 115 kV line	20	8/1/2013	Kings
Solar	Henrietta-Guernsey 70 kV	20	12/31/2011	Kings
Solar	Oro Loma 115 kV	20	12/25/2011	Merced
Solar	Dairyland—Legrand 115 kV	20	1/1/2012	Madera
Solar	Henrietta-Tulare Lake 70 kV	20	12/31/2012	Kings
Solar	Henrietta Sub 70 kV Bus	20	12/31/2012	Kings
Solar	Arco 70 kV	20	1/15/2013	Kings

Source: CAISO 2012 Generator Interconnection Queue
kV = kilovolt

J.3.2 Ancillary Service Market

CAISO procures various ancillary services in the market. In the day-ahead and real-time markets, CAISO procures regulation reserve, spinning reserve, and non-spinning reserve. In the hour-ahead market, it procures only operating reserves, which comprise spinning and non-spinning reserves. The ancillary services procured in the market are defined below.

- Regulation Reserves: The generating resources that are running and synchronized with the grid, which can provide reserve capacity so that the operating levels can be increased or decreased within 10 minutes through Automatic Generation Control (AGC) signal based on the regulating ramp rate of the resource. CAISO operates two distinct capacity markets for this service, upward and downward regulation reserve.
- Spinning Reserves: Reserved capacity provided by generating resources that are running with additional capacity that is capable of ramping over a specified range within 10 minutes and able to run for at least 2 hours. CAISO needs this reserve to maintain system frequency stability during emergency operating conditions.
- Non-Spinning Reserves: Reserved capacity provided by the generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then able to run for at least 2 hours. The CAISO needs non-spinning reserve to maintain system frequency stability during emergency conditions.

The market participants (i.e., electricity providers) can self-provide any or all of these ancillary service products, bid them into the CAISO markets, or purchase them from CAISO. The same resource capacity may be offered for more than one ancillary service into the same CAISO market at the same time. In addition, resources that have registered with a metered subsystem (MSS) that has elected the load following option may submit self-provision bids for load following up and load following down. Scheduling coordinators (SCs) simultaneously submit bids to supply the ancillary service products to CAISO in conjunction with their preferred day-ahead and hour-ahead schedules.

J.3.3 Sacramento Municipal Utility District

The Sacramento Municipal Utility District (SMUD), established in 1946, is the nation's sixth largest community-owned electric utility in terms of customers served (approximately 590,000) and covers a 900 square-mile area that includes Sacramento County and a small portion of Placer County. The service territory of SMUD is shown in Figure J-4.

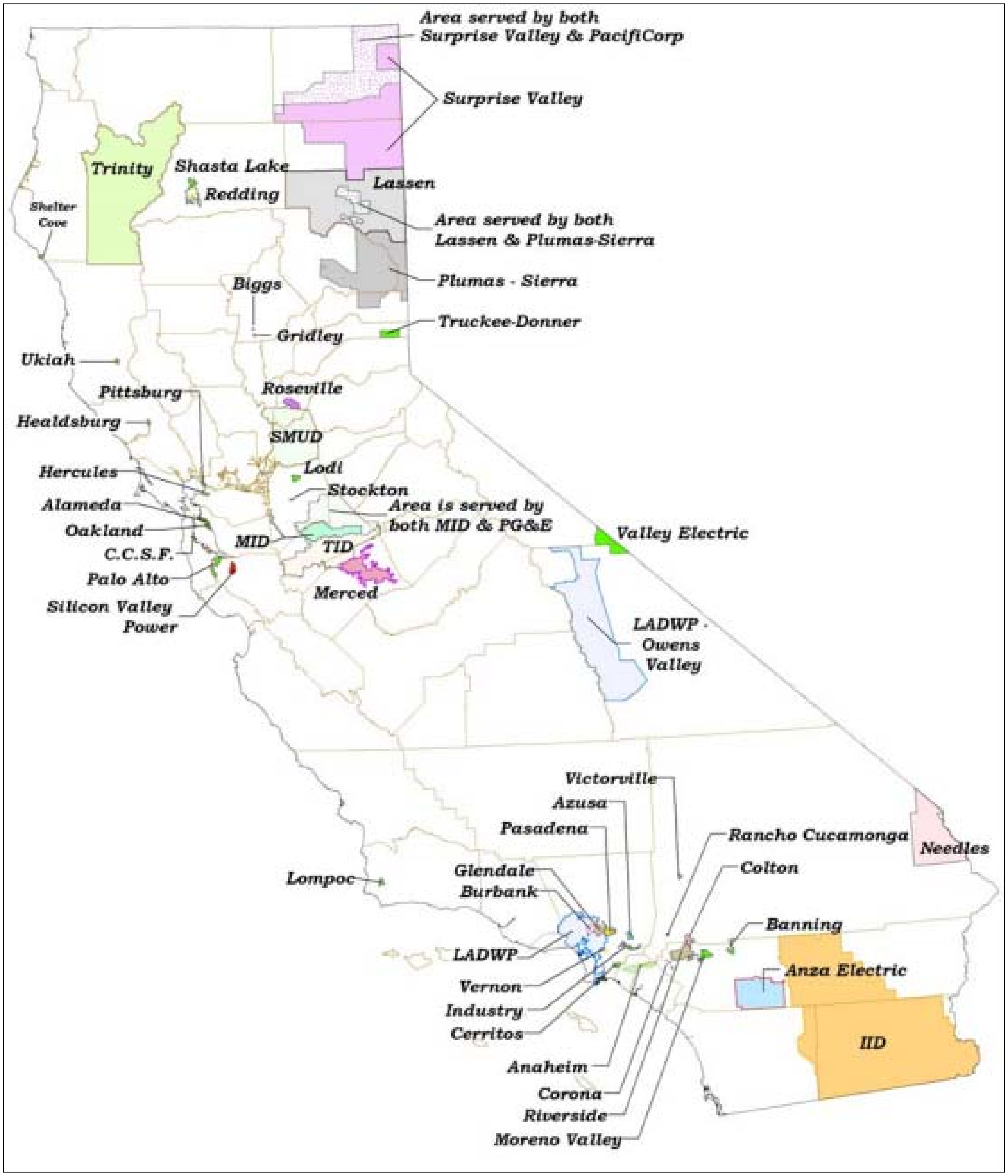


Figure J-4. SMUD Service Territory in California (Source: CEC 2012)

As part of the biennial resource adequacy and resource plan assessments for publically owned utilities, California Energy Commission (Commission) published its biennial report in November 2009 detailing the need and availability of generation resources to meet the future load and planning reserve margin requirements within the territory of publically owned utilities (California Energy Commission 2009). The report indicates that SMUD will be able to meet its resource adequacy requirements in the near term; however, in 2018 SMUD's generation resources may not be sufficient to meet its load and planning reserve margin obligations. The deficiency expected in 2018 is estimated at 347 MW, but the Commission does not expect this to be an issue due to the lead time available to resolve the expected deficiency.

Transmission Expansion Plans and New Generator Additions

SMUD also carries out an annual 10-year transmission planning process to ensure that NERC and Western Electricity Coordinating Council (WECC) Reliability Standards are met each year of the 10-year planning horizon. Major projects that have been proposed in the 2010 transmission plan for the 2016 to 2020 time period are listed in Table J-8 (Sacramento Municipal Utility District 2010). These projects are expected to improve the reliability of SMUD's electric system as well as increase its load serving capability.

Table J-8. Proposed Transmission Upgrades in SMUD 2016–2020

Project Name	Project Description	Expected In-Service Date
Franklin 230/69 kV Substation	New Distribution Substation	May 31, 2016
O'Banion-Sutter 230 kV Double Circuit Transmission Line Conversion	Add circuit breakers to convert O'Banion-Sutter line to double circuit tower line	May 31, 2016
Installation of 200 MVAr transmission capacitors	Install transmission capacitors	May 31, 2019
400 MW Iowa Hill Pump Storage Facility	New Hydropower Plant in the Upper American River Project	May 31, 2020
Lake-Folsom 230 kV and Folsom - Orangevale 230 kV Reconductoring	Reconductor the Lake-Folsom – Orangevale 230 kV Lines	May 31, 2020

kV = kilovolt
MW = megawatts

The New Melones Power Plant physically resides in the CAISO Balancing Authority (BA) Area. However, Sierra Nevada Region (SNR)[5], SMUD, and the CAISO operate New Melones as a pseudo-tie generation export from CAISO into the SMUD BA Area (Western 2010). This arrangement implies that New Melones is electronically and operationally included as part of the SMUD BA Area. For purposes of qualifying capacity, SNR has designated the New Melones Power Plant as part of the Central Valley Project (CVP) resource in the SMUD BA Area. The location of New Melones is shown in Figure J-1.

[5] Western, Sierra Nevada Region (SNR), is a certified scheduling coordinator and an LSE for certain loads and resources within the CAISO Balancing Authority Area.

J.3.4 Turlock Irrigation District

The Turlock Irrigation District (TID) operates as a BA located between Sacramento and Fresno in California's Central Valley (California Transmission Planning Group 2011). Westley 230 kV and Oakdale 115 kV lines provide import access for TID. The TID BA incorporates all 662 square miles of TID's electric service territory (Figure J-5) as well as a 115 kV loop with three 115 kV substations owned by the Merced Irrigation District (Merced ID). The Merced ID facilities are interconnected to TID's August and Tuolumne 115 kV substations and are located just south of TID's service territory and north of the city of Merced. TID is the majority owner and operating partner of the Don Pedro Hydroelectric Project, with 68.46 percent ownership; MID has a 31.54 percent ownership.

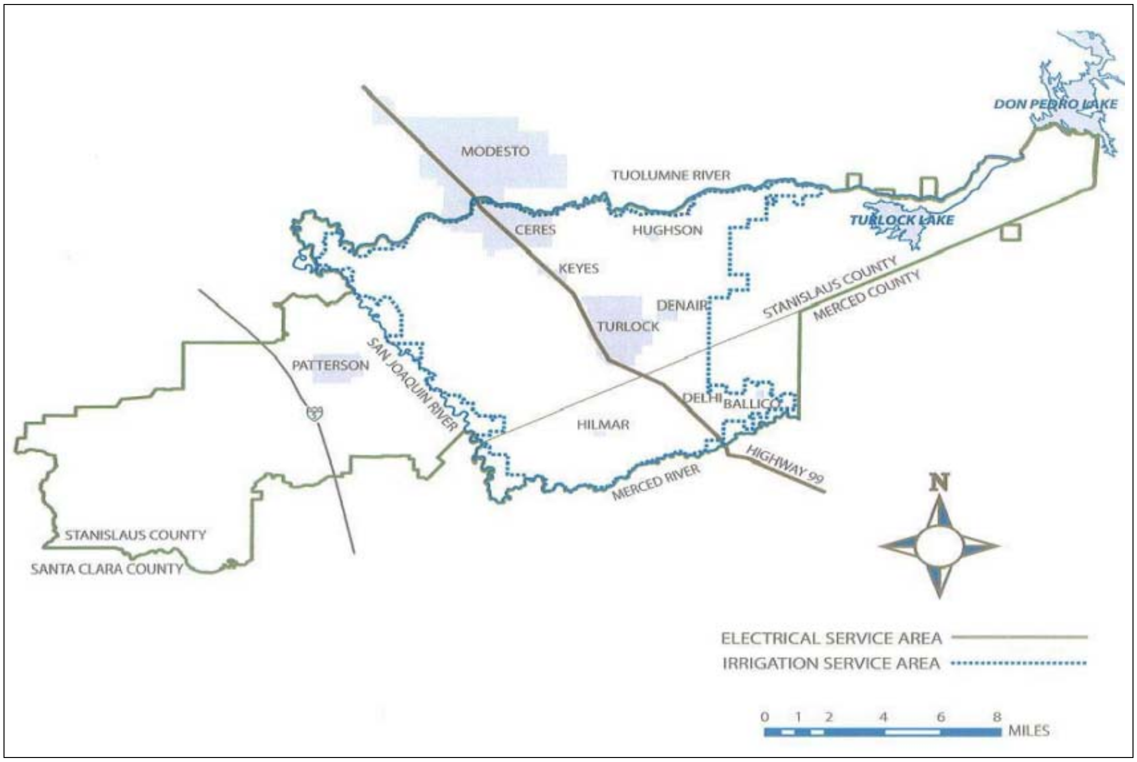


Figure J-5. Turlock Irrigation District Service Area (Source: California Transmission Planning Group 2011)

Transmission Expansion Plans and New Generator Additions

TID is currently working on two major generation projects. One of these, the Almond 2 Power Plant, has been approved by the board of directors while the Red Mountain Bar Pumped Storage Power Plant project is in the study phase. Key characteristics and benefits of these projects are summarized in Table J-9 (TID 2011).

Table J-9. Summary of Almond 2 and Red Mountain Bar Power Plants

Project Name	Key Characteristics	Project Objective(s)	Expected In-Service Date
Almond 2 Power Plant (174 MW)	Natural-gas fired simple-cycle peaking power generation facility. Located in Stanislaus County.	Meet reliability obligations as a Balancing Authority. Improve the economy, efficiency, and flexibility of the District's electrical system, including the integration of intermittent renewable resources.	2012
Red Mountain Bar Pumped Storage (880 MW)	Joint project with MID. Located near Sonora in Tuolumne County.	Proposes to use the existing Don Pedro Reservoir as the lower pool from which to pump water to a newly constructed upper reservoir. Improve reliability of the electric grid by quickly replacing solar and wind generated electricity that could vary significantly with weather conditions.	=

MW = megawatts
MID = Modesto Irrigation District

J.4 Effects on Generating Capacity and Electric Grid

In Section J.2, *Energy Generation Effects*, the total annual or monthly amounts of energy generated (in GWh) by each LSJR alternative and the baseline were estimated and compared. This section considers the effect of the LSJR alternatives on the amount of available power generating capacity during the peak energy-use months of July and August (peak generating capacity) from the major hydropower facilities in the LSJR watershed (New Melones, New Don Pedro, and New Exchequer) and the corresponding potential to affect the functioning of the electric grid (power flow assessment) during the peak energy-use months of July and August.

J.4.1 Peak Generating Capacity

Peak generating capacity, expressed as megawatts (MW), refers to the available generating capacity during the peak energy-use months of July and August. This is the power that can be generated with full design flow through the turbines at a given set of reservoir storage elevation conditions as estimated by the WSE on average during July and August. As the storage elevation in the reservoir is increased, the generating capacity at full flow through the turbines is increased. The *Water Supply Effects Model—SJR Tributaries* as developed by State Water Resources Control Board of California was used to estimate the end-of-month reservoir storage elevations and monthly release rates for each LSJR alternative and baseline across the 82-year period between water years 1922 and 2003.

Generating capacity during July and August is calculated based on estimates of the available head (i.e. the difference between end-of-month reservoir storage elevation and tail-water elevation) for generating electric power. Table J-10 shows the maximum head (i.e. difference between the maximum elevation and tail-water elevation), and the corresponding maximum capacity for the New Melones, Don Pedro, and New Exchequer hydropower facilities. Since the power generation capacity in MW is directly proportional to the available head, the available capacity of affected hydropower plants in any month under each LSJR alternative was estimated by prorating the maximum plant capacity by the available head estimated from the WSE model. For example, if for any month, the model estimated available head for New Melones was 500 feet, then using the maximum head and maximum capacity values from Table J-10, its available capacity for that month was estimated at 256 MW (300 MW x [500 feet/585 feet]).

Table J-10. Existing Maximum Power Generation Capacity

Power Plants	Maximum Elevation (Feet)	Tail-water Elevation (Feet)	Maximum Head (Feet)	Maximum Capacity (MW)
New Melones	1,088	503	585	300
Don Pedro	830	310	520	203
New Exchequer	867	400	467	95

MW = megawatt

Figures J-6 and J-7 present the total available generating capacity (MW) from New Melones, Don Pedro and New Exchequer using this approach for peak demand months July and August respectively across the 82 years of WSE simulated hydrology for the LSJR alternatives and baseline. These figures show little change in the distribution of available generation capacity in both of these months for LSJR Alternatives 3 and 4, and a slight increase for LSJR Alternative 2 when compared to the baseline.

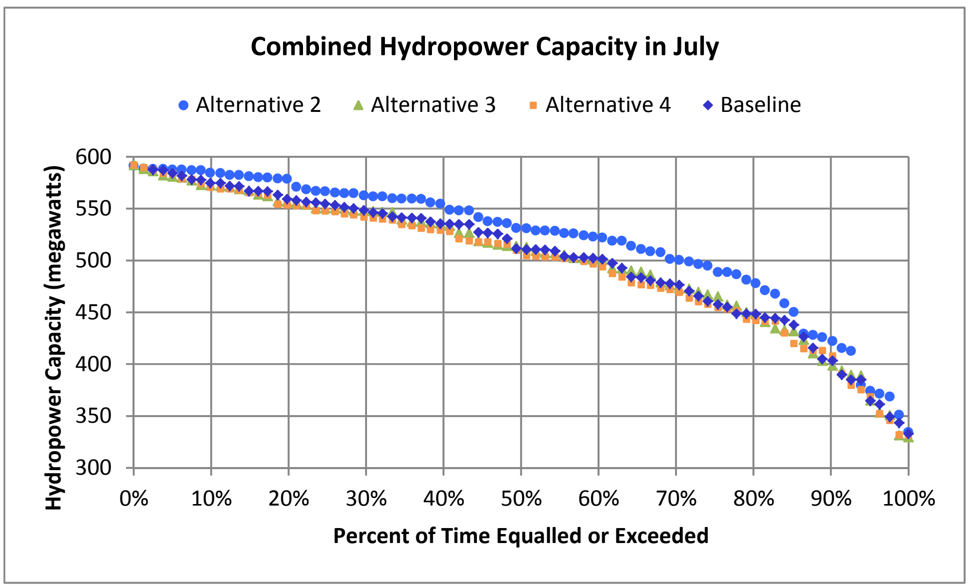


Figure J-6. Exceedance Plot of Total Generating Capacity (megawatts) in July, Across 82 Years of Simulation, from the Three Major Tributary Hydropower Facilities, Comparing LSJR Alternatives 2–4 and Baseline.

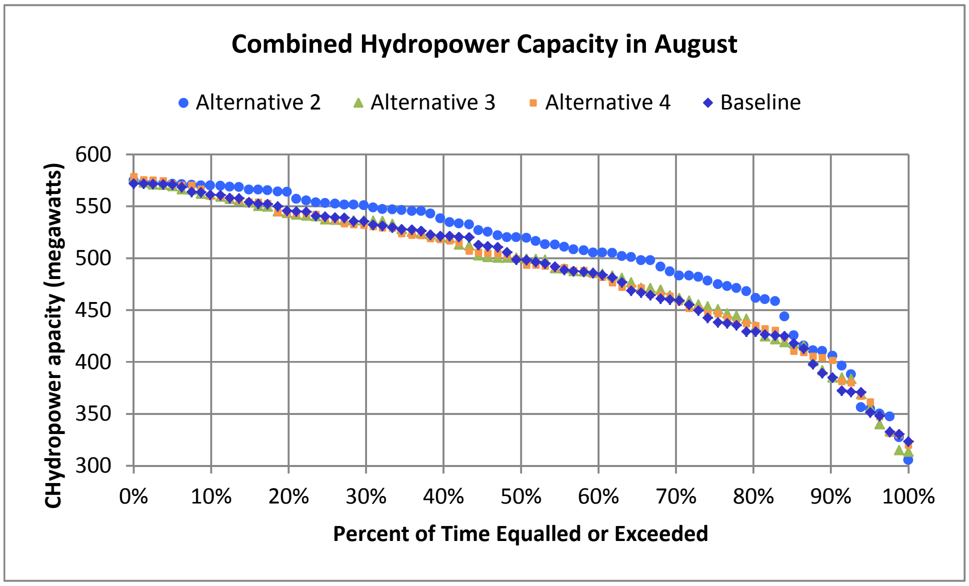


Figure J-7. Exceedance Plot of Total Generating Capacity (megawatts) in August, Across 82 Years of Simulation, from the Three Major Tributary Hydropower Facilities, Comparing LSJR Alternatives 2–4 and Baseline.

J.4.2 Power Flow Assessment Methodology

Even though the above analysis found a less than significant effect on peak generating capacity based on the change is reservoir head during July and August for the LSJR alternatives, this section will evaluate both a 5 percent and 8 percent reduction in the peak capacity in order to assess the sensitivity of the electric grid to changes that may not be otherwise captured in the WSE modeling.

According to NERC, reliability of an electric system comprises two interrelated elements—adequacy and security. Adequacy refers to the amount of capacity resources required to meet peak demand and security refers to the ability of the system to withstand contingencies or other system disturbances, such as the loss of a generating unit or transmission line. Both of these reliability aspects can be gauged from sub-station voltages and transmission line loadings. A steady state power flow assessment of the California grid was performed to check if reduction in hydropower capacities of the three dams would adversely impact the grid reliability as defined by NERC.[6]

The power flow assessment was a multi-step process. These steps are listed and detailed further below.

- Prepare a Base Case (California electric grid model under normal and contingency conditions, assuming the facility is in normal operation).[7]
- Prepare two separate Change Cases (California electric grid model under normal and contingency conditions assuming reduced output of the facilities) assuming a 5 percent and 8

[6] Power flow software models simulate the operation of the grid and calculate substation voltages and power flowing on transmission lines/transformers. These calculated values can then be compared with standard voltage limits and line/transformer thermal ratings to identify violations.

[7] Under normal conditions, all generation and transmission facilities are assumed to be in service. Contingency conditions refer to the unplanned outage of power system equipment.

percent reduction in available hydropower generating capacity from the New Melones, New Don Pedro, and New Exchequer hydropower facilities.[8]

- Develop criteria for selection of generator and transmission contingencies.
- Develop criteria for voltage and thermal limits.
- Select the areas where transmission line/transformer loadings and sub-station voltages would be monitored.

Base and Change Case Development

The base case was the latest 2011 heavy summer (high summer power demand) electric grid model of the entire Western Interconnection developed by WECC. This case had a detailed representation of the California electric grid. A summary of load, generation, area interchange, and area losses in the base case is shown in Table J-11.

Table J-11. Representation of the California Electric Grid

Power Flow Area #	Power Flow Area Name	Area Generation (MW)	Area Load (MW)	Area Interchange (MW)	Area Loss (MW)
10	NEW MEXICO	2,955	2,690	105	159
11	EL PASO	978	1,644	-730	64
14	ARIZONA	26,323	19,753	6,284	286
18	NEVADA	5,721	6,338	-708	91
20	MEXICO-CFE	2,108	2,304	-230	34
21	IMPERIALCA	1,100	978	90	31
22	SANDIEGO	3,666	4,930	-1,371	107
24	SOCALIF	17,929	25,278	-7,842	492
26	LADWP	4,554	6,537	-2,410	427
30	PG AND E	27,231	27,050	-784	966
40	NORTHWEST	30,956	25,165	4,507	1,285
50	B.C.HYDRO	11,137	7,900	2,572	665
52	FORTISBC	879	733	127	20
54	ALBERTA	9,971	10,022	-400	349
60	IDAHO	4,058	3,703	139	216
62	MONTANA	3,192	1,837	1,252	102
63	WAPA U.M.	56	-44	92	7
64	SIERRA	1,889	2,037	-208	60
65	PACE	7,914	8,528	-918	304
70	PSCOLORADO	7,531	7,840	-510	200
73	WAPA R.M.	5,998	4,870	941	188

MW = megawatt

[8] Under normal conditions, all generation and transmission facilities are assumed to be in service. Contingency conditions refer to the unplanned outage of power system equipment.

Two change cases were developed for the hydropower generation facilities. One change case was prepared with the peak generating capacity of each hydropower facility (New Melones, New Don Pedro, and New Exchequer) reduced by 5 percent of its value in the base case. The second change case was prepared assuming 8 percent less available peak generating capacity than their output in the base case. Table J-12 summarizes the modeled cases. The total peak generating capacity for these three hydropower facilities assumed in the WECC base case simulation is 409 MW and represents a level that is exceeded about 90 percent of years in both July and August as shown in Figures J-7 and J-8 respectively.

Table J-12. Description of Test Cases Modeled

Case Description	Peak Generating Capacity	Normal Conditions	Contingency Conditions
Base Case	Normal[a.]	√	√
Change Case #1	Reduced by 5%	√	√
Change Case #2	Reduced by 8%	√	√

a. WECC base case peak generating capacities for New Melones, New Don Pedro, and New Exchequer facilities are 231 MW, 90 MW, and 88 MW respectively (409 MW total) (MW = megawatts).

Contingency Selection Criteria

Base and change cases were analyzed for single contingency outage of all the transmission facilities rated 115 kV and above within the BA of the generating facilities, and 230 kV and above in the neighboring BAs or regions.[9] Single contingency outage of all generators rated 100 MW or above, both within the BA of the facilities and in the neighboring BAs, were also used to analyze the performance of electric grid under base and change cases. In the power flow, all the facilities are shown to be a part of PG&E area with Southern California Edison, Northwest, and Sierra as neighboring regions.

Voltage and Transmission Line Limits

The transmission line limits used in the study were the normal and Long-Term Emergency (LTE) ratings. Under normal and contingency conditions, transmission line flows are expected to remain within the normal and long-term emergency ratings, respectively. Similarly, voltage limits were established relative to the nominal voltages. Under normal conditions, system operators regulate nodal voltages within ±5 percent of their nominal values. Under contingency conditions, this limit is relaxed to ±10 percent of the nominal value.

Criteria for Monitoring Transmission Elements

Within the BA of the facilities, the following criteria for monitoring transmission line/transformer loadings and sub-station voltages:[10]

- All transmission lines with nominal voltage greater than 115 kV.

[9] In the context of this analysis, neighboring region or neighboring BA is defined as a region which has a direct transmission link with the region in which the facility is located.

[10] The loading of a transmission line or transformer is measured as a ratio of the actual flow across the facility in amperes or mega-volt amperes to the rated value of current. In this analysis, only those lines/transformers are recorded whose loading exceeds 90% of the applicable rating.

- All transformers with both nominal primary and secondary voltage greater than 115 kV.

In the neighboring Balancing Authorities, the following criteria for monitoring transmission/transformer loadings and sub-station voltages:

- All transmission lines with nominal voltage greater than 230 kV.
- All transformers with both primary and secondary voltage greater than 230 kV.

The WECC paths in California (referred to as "interfaces" hereafter) were also monitored. These are listed in Table J-13.[11]

Table J-13. WECC Paths Monitored

WECC Path Number	WECC Path Name
15	Midway-Los Banos
24	PG&E-Sierra
25	PacifiCorp/PG&E 115 kV Interconnection
26	Northern-Southern California
52	Silver Peak-Control 55 kV
60	Inyo-Control 115 kV Tie
66	COI
76	Alturas Project

Source: Western Congestion Analysis Task Force 2006.
kV = kilovolt

J.4.3 Power Flow Simulation Tools

The *GE® Positive Sequence Load Flow* (PSLF) model was used for this analysis. PSLF is ideal for simulating the transfer of large blocks of power across a transmission grid or for importing or exporting power to neighboring systems. The model can be used to perform comprehensive and accurate load flow, dynamic simulation, short circuit and contingency analysis, and system fault studies. Using this tool, engineers can also analyze transfer limits while performing economic dispatch. PSLF can simulate large-scale power systems of up to 80,000 buses.[12]

J.4.4 Assumptions for Facilities

The assumptions for the generation facility characteristics and interconnection substations are shown in Table J-14. Other assumptions, including transmission facility normal and long-term emergency ratings, transmission line impedances, and substation nominal voltages were defined in the WECC power flow cases used for the assessment.

[11] WECC Paths refer to either an individual transmission line or a combination of parallel transmission lines on which the total power flow should not exceed a certain value to maintain system reliability.

[12] In Power Flow modeling a "bus" represents all the sub-station equipment that is at the same voltage level and is connected together.

Table J-14. Unit Assumptions for the Engineering Assessment

Unit Name	Unit Bus Number in WECC Power Flow Case	Interconnection Voltage (kV)
New Melones	37561, 37562	230
Don Pedro	38550, 38552, 38554	69
New Exchequer	34306	115

kV = kilovolt

J.4.5 Results and Conclusions

Thousands of transmission lines, nodal voltages, and interfaces under normal system conditions and contingency outages of hundreds of transmission lines and generators were monitored under the base and change cases. The base case sub-station voltages and line/transformer loadings were then compared with those of the change cases. If the comparison showed that sub-station voltages or transmission line/transformer loadings are within limits in the base case, but outside the limits in the change cases (i.e., the 5 percent and 10 percent identified in Section J.4.2, *Power Flow Assessment Methodology*), the unimpaired flow alternatives could be considered to have an adverse impact on the reliability of California's electric grid. Results of the power flow assessment are discussed below.

Comparison between Base and Change Case Line/Transformer Loadings under Normal Conditions

Under normal operating conditions, no transmission line or transformer was found that violated the ratings exclusively in the change cases.

Comparison between Base and Change Case Line/Transformer Loadings under Line/Transformer Contingencies

When base and change cases were studied under transmission line and transformer contingencies, no line/transformer limit violation was found for the base case and change case #1. However, for change case #2, the 230 kV line between Borden and Gregg substations showed a minor violation (100.04 percent of its LTE rating) under the outage of the 230 kV line between Gregg and Storey substations. This minor overload was mitigated through a 5 MW reduction in the total power dispatch (1,148 MW in the base case) of the three Helms units. The new loading of the monitored element after this re-dispatch was 99.81 percent.

Comparison between Base and Change Case Line/Transformer Loadings under Generator Contingencies

Under generator contingencies, no line/transformer limit violations were found that could be exclusively attributed to either change case.

Comparison between Base and Change Case Substation Voltages under Normal and Line/Transformer/Generator Contingencies

No voltage violations were found that could be exclusively attributed to the reduced hydropower capacity in the change cases.

Comparison between Base and Change Case Interface Loadings under Normal and Line/Transformer/Generator Contingencies

No interface limit violations were found that could be exclusively attributed to the reduced hydropower capacity in the change cases.

In conclusion, an engineering assessment was performed to determine if implementation of the unimpaired flow alternatives on the tributaries, and the resulting change in hydropower generation at the hydropower plants, would adversely impact the reliability of California's electric grid.

As described in Section J.4.1, *Capacity Reduction Calculation Methodology*, there is a less-than-significant reduction in available hydropower generating capacity associated with the LSJR alternatives in the peak summer load months of July and August. Additional evaluation determined the electric grid could adapt to 5 percent and 8 percent reductions in available generating capacity from the New Melones, New Don Pedro, and New Exchequer hydropower facilities with less-than-significant impact on its reliability. Based on the results of this study, the San Joaquin River Flow Objectives project would not adversely impact the reliability of California's electric grid.

J.5 References

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