PUBLIC

Eagle Mountain Pumped Storage Project No. 13123

Final License Application

Volume 1 of 6

Exhibit B:

Project Operation and Resource Utilization

Palm Desert, California

Submitted to: Federal Energy Regulatory Commission
Submitted by: Eagle Crest Energy Company

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1 Description of Alternative Sites Considered

1.1 Pumped Storage Location Alternatives

The proposed project is located at the site of the former Kaiser Iron Mine, an open-pit operation that ceased iron ore production in the early 1980s. The site is located near the Town of Eagle Mountain in Riverside County, California, approximately 30 miles east of Indio, and 13 miles north of I-10 and the town of Desert Center.

The site was selected for pumped storage for the following reasons:

- Two existing mine pits are located within 14,000 feet of each other, with an elevation difference between the pits of approximately 1,500 feet. The pits can be used for water storage, with the Central Pit serving as the upper reservoir and the East Pit serving as the lower reservoir for a hydroelectric pumped storage development. The storage space available in the two mine pits is about 28,000 acre-feet in total. Construction of dams to create this amount of storage could cost up to $190 million at sites with similar topography that would require major dams. Thus this site offers a rare opportunity to minimize costs of developing reservoir storage.

- The geology of the project area is dominated by rock formations comprised of good quality materials for construction of the dams, water conveyance tunnels, and underground chambers associated with a pumped storage project.

- The site is within about 13 miles of a National Interest Electric Transmission Corridor, which includes the Palo Verde to Devers corridor, which extends from the Palo Verde Nuclear Plant in Arizona to the Devers Substation near Palm Springs. The project proposes to interconnect to the planned Devers-Palo Verde No. 2 transmission line, 13.5 miles from the project site.

- The site is located adjacent to the Chuckwalla Basin, which has a source of water from the Chuckwalla Valley Aquifer (groundwater) to initially fill the reservoirs and to provide makeup water for evaporation and seepage.

- The site has potential to firm the energy produced by a growing regional portfolio of solar and wind power projects making it possible to integrate a high level of renewable energy generation sources and maintain reliable grid operations and provide peak power demands to meet California's energy needs. California's renewable portfolio standards (RPS) call for 33 percent of electrical generation to come from renewable sources by 2020.

The site is located near existing and proposed renewable energy generation, including the San Gorgonio Pass wind farm west of the community of Palm Springs. Major large scale solar projects are proposed for the Chuckwalla Valley and surrounding desert areas, and the Palo Verde Mesa approximately 40 miles east of the project site.

1.2 Transmission Alternatives

The preferred transmission line route has been determined to be one that interconnects the proposed Project switchyard to a proposed Interconnection Collector Substation at Desert Center, which will be adjacent to the planned Devers -Palo Verde No. 2 (DPV2) 500-kilovolt (kV) line owned by Southern California Edison (SCE). The Collector substation could serve the proposed solar projects in the Chuckwalla Valley as well. The approximate length of the interconnection line is 13.5 miles. The proposed DPV2 500-kV line will be under the operational control of the California Independent Systems Operator (CAISO).

The proposed routing from the Project was selected as the shortest route that would most economically supply power to, and receive power from, the southwestern grid, avoiding sensitive environments to the greatest extent feasible. Operational load-flow studies will be conducted by the CAISO to determine exact interconnection requirements.

The interconnection of the Project to a collector substation at Desert Center will require the construction of the DPV2 transmission line in order to enable the Project to access the California market. The CAISO has approved SCE to construct the DPV2 transmission line and the California Public Utilities Commission (CPUC) has reached similar conclusions in granting SCE a Certificate of Public Convenience and Necessity (CPCN) to construct DPV2 in 2005. The CPUC approved the DPV2 Project on January 25, 2007 in Decision D.07-01-040 and certified the California Environmental Quality Act (CEQA) Environmental Impact Report (EIR) as being in compliance with the requirements of CEQA.

The Arizona Power Plant and Line Siting Committee, a committee of the Arizona Corporation Commission (ACC), approved and recommended the project for final ACC approval in March 2007. However, the project was denied by the ACC in June 2007. In May 2008, SCE filed a petition with the CPUC seeking permission to start construction in California to satisfy interconnection requests for new renewable and conventional generation projects in the Southeastern part of the State for the benefit of the region.

Based on information provided on SCE's website, SCE's priority and preference is to seek a satisfactory resolution with the ACC, but SCE is assessing all options to obtain approval of the project in Arizona. SCE is simultaneously pursuing two approaches to secure regulatory approval: a new ACC filing and the FERC Transmission Line Siting process. SCE remains committed to obtaining permitting approval for DPV2 facilities in Arizona and is pursuing all available options, including applying for federal transmission line siting, per Section 1221 of the Energy Policy Act of 2005.

The Eagle Mountain Project is targeting the California, Arizona, and Nevada markets to supply peaking generation and ancillary services to the investor owned utilities as well as the municipal utilities. As the peak load demand and the addition of intermittent generating resources in these markets continue to grow, energy storage for peaking generation with load following capability, quick response spinning reserves, and voltage regulation resources will be an essential part of the Western region's energy system resource mix.

Table 1-1 summarizes the various transmission components of the Project. The single-line diagram can be found in Exhibit F.

Table 1-1: Summary of Proposed Transmission Line Project Components

Proposed Route and Right-of-Way • Transmission Line Length: approximately 13.5 miles. • Project Connection Point: A new substation/switching station at Eagle Mountain. • Network Connection Point: The Proposed Interconnection Collector Substation at Desert Center, which will interconnect to the planned DPV2 500-kV line owned by SCE. • Right-of-Way Width: 200 feet. The right-of-way width would be reduced in specific locations to mitigate potential impacts to resources (e.g., historic trails, adjacent land restrictions, existing roads and highways, and biological and cultural resources). • Total Right-of-Way Acreage: approximately 330 acres for the linear ROW.

Transmission Line Facilities (500 kV, double circuit)
• Conductors: Two, three-phase AC circuits consisting of three 1.5 to 2-inch ACSR conductors per circuit.
• Minimum Conductor Distance from Ground: 35 feet at 60°F and 32 feet at the maximum operating temperature.
• Shield Wires: Two ½- to ¾-inch-diameter wire(s) for steel lattice.
• Transmission Line Tower Types:
  - Steel Lattice Tower along entire route.
  - Structure Heights (approximate): Steel Lattice – 175 to 235 feet.
• Average Distance between Towers: Steel Lattice – 1,056 feet.*
• Total Number of Towers (approximate): 54-68*

Substation Facilities • A new substation/switching station at Eagle Mountain requiring a total area of approximately 25 acres would be constructed. • Interconnection Collector Substation at Desert Center: A Collector Substation would be constructed at Desert Center, west of Desert Center, California, to accommodate interconnection of this Proposed Project and other proposed projects in the same area for delivery to the DPV2 transmission line.
Communications Facilities • Systems: Digital Radio System, microwave, VHF/UHF radio, fiber optics. • Functions: Communications for fault detection, line protection, SCADA, two-way voice communication.

The project has evaluated several potential points of interconnection to the transmission grid. In the initial planning stages, ECE considered an interconnection request to connect at the Devers Substation, near Palm Springs. This would have required an interconnection line of 83 miles, through an already crowded transmission corridor. Obstacles to this alternative include cost for construction; difficulty of obtaining right-of-way, particularly in the communities of Indio and Cathedral City; potentially significant impacts to the natural and human environment; and cultural resource concerns of the Aqua Caliente Band of Cahuilla Indians.

As an alternative, ECE proposed to interconnect at SCE's proposed Midpoint Substation (also known as the Colorado River Substation). This proposal was presented in the Pre-application Document (filed with FERC January 2008), and the Draft License Application (filed with FERC in June 2008). This proposed route was 50.5 miles from the project site to the point of interconnection. The proposed route crossed the Chuckwalla Valley Dune Thicket Area of Critical Environmental Concern (ACEC), and required a crossing of the I-10 Interstate Highway.

The project requires a double circuit 500 kV line, which will require construction of new transmission towers to support and route to the interconnection substation. Several stakeholders have requested ECE consider installing its transmission lines on existing transmission towers owned by Metropolitan Water District (MWD). This is not a feasible alternative given the size of the towers, the size and weight of the new lines, and alignments of existing transmission lines in the area.

A substation site located at the I-10 and Eagle Mountain Road junction was considered but dismissed due to cultural resource concerns related to the historic (World War II) Desert Training Center hospital site. In addition, this location would have conflicted with an existing high pressure gas line.

1.3 Water Supply Alternatives

The Project's proposed water supply is groundwater. ECE is acquiring the requisite property to develop ground water in the Chuckwalla Basin to initially fill the reservoirs and for annual make-up water. Three wells will be utilized to provide initial reservoir fill. Thereafter, only one of these wells will be required for water to replace losses due to seepage and evaporation, with a second well maintained as a backup water supply. ECE proposes to install new wells connected to a central collection pipeline corridor described in Exhibits A and F, and evaluated in Exhibit E.

The alternatives for water supply are limited. The Project is not located on a natural stream nor would the small watershed drainage area that would flow into either or both of the reservoirs provide nearly enough water to offset seepage losses and evaporation. Therefore, the water supply must come from either local groundwater, or through the MWD's Colorado River Aqueduct (CRA).

ECE investigated the alternative of purchasing water from a third party and having the water delivered to MWD. In exchange, MWD could provide the same amount of water to the project from the CRA. Potential sources of water supply for the exchange would most likely come from the purchase of surplus water in the San Joaquin Valley and/or Sacramento Valley. The CRA could also be the source of make-up water supplies; however, it would require long-term contracts for exchange water and for wheeling through existing facilities.

This alternative was rejected for several reasons. Several potential vendors were approached regarding the purchase of surplus surface water and banked groundwater. While it is possible to make an arrangement of this type, it is difficult to find willing sellers during drought years. In addition, the costs and environmental permitting requirements are potentially a significant barrier. The potential for an arrangement of this type was discussed with MWD staff, but the MWD Board would need to approve of any such wheeling or exchange agreement. As MWD has stated in their comment letters on the project, they have not agreed to provide water to the project through the CRA. Finally, water supplies in the CRA contain quagga mussels. The introduction of quagga mussels into the project reservoirs would be undesirable.

2 Description of Alternative Facility Designs, Processes, and Operations

Several alternative facility design configurations, and project installed capacities, were considered during project planning. These alternatives are discussed below.

2.1 Powerhouse Location

The choice between a surface and underground powerhouse was studied early in Project development. The required depth of unit setting below minimum lower reservoir pool and the limited ground cover, which would result in a long length of steel-lined power tunnel, indicated that a surface powerhouse would be more costly in comparison with an underground powerhouse. An underground powerhouse could be constructed closer to the lower reservoir; however, this arrangement would involve a longer high-head tunnel posing greater concerns about hydraulic transients and surge control.

The underground powerhouse could be located anywhere between the two reservoirs where suitable geologic conditions exist, at a depth that satisfies the unit submergence requirements. The proposed location was selected because of the expected existence of sound granitic rock away from fractured and diverse conditions associated with ore zones, a route for the power waterways that is near to a direct connection between the upper and lower reservoirs, a minimum length of steel lining of the power waterways, proximity to a suitable location for surge shafts and chambers, and a reasonable length of access tunnel at an acceptable grade from the surface to the powerhouse.

2.2 Installed Capacity

The selected installed capacity of 1,300 megawatts (MW) is judged to be consistent with the capacity needs of the southwestern U.S. at the time when the Project could be in operation, probably around 2015-2016. Staging studies indicated that an initial installed capacity of 1,000 to 1,500 MW could be economically engineered to enable a doubling of generating capacity at some future date.

2.3 Storage Capacity

The storage capacity of the reservoirs is directly related to the amount of energy storage provided by the Project. The amount of storage proposed for the Project will support continuous rated capacity generation for a period of 10 hours during each day while pumping back for a period of 12 to 14 hours during off-peak periods each day. (Off-peak periods are from 10:00 PM to 6:00 AM. Significant wind energy is produced at night as well. A working volume of 17,700 acre-feet will be provided, which corresponds to 18.5 hours of storage at full plant discharge (11,600 cubic feet per second [cfs]). The 17,700 acre-feet of active reservoir storage is equivalent to 22,000 megawatt hours (MWh) of energy production. The maximum potential energy generation on an annual basis is 4,308 gigawatt hours (GWh). Alternate generating periods and variable pump-back periods to accommodate off-peak wind and solar power generation will also be considered during further investigations. The 10-hour generating period was selected because it provides flexibility in Project operations.

2.4 Upper Reservoir

Some flexibility exists in the selection of the minimum and maximum operating levels of the upper reservoir. The respective levels of El. 2485 and El. 2343 were selected based on the required submergence for the intake structure at the upper reservoir and the energy storage required to support the intended weekly operating cycle. Also, the range of levels was checked to ensure that the maximum and minimum operating heads will remain within the range that is acceptable for reversible pump/turbines.

The foundation conditions at the upper reservoir are judged to be suitable for either a concrete-faced, rockfill dam or a roller-compacted concrete (RCC) gravity dam. Selection of the type of dam will be made during subsequent design and following intensive subsurface explorations and materials testing. The layouts presented in this application are based on constructing an RCC dam, using on-site mine tailings that would be processed and/or using materials generated from tunnel and underground structure excavations. The final decision on type of dam will be based on final engineering studies and on-site explorations, as well as cost considerations.

2.5 Lower Reservoir

The capacity of the East Pit, with the low point of its rim at 1,100 feet, is about 23,000 acre-feet, which exceeds the needed storage capacity for a 1,300 MW project (total of 21,900 acre-feet, including dead storage). Therefore, no dam structures are needed at the lower reservoir. With the invert of the I/O structure at El. 925 feet, there is approximately 4,200 acre-feet of inactive storage. The operating levels of the lower reservoir, between El. 925 and El. 1092, will maintain the operating head of the pump/turbines in an acceptable range.

2.6 Water Conductors, Penstocks, Tailrace, and I/O Alternatives

The main water conductor connecting the upper reservoir to the powerhouse would be bored with a tunnel boring machine (TBM) or drilled and blasted into and through the Eagle Mountain, with a finished diameter of 29 feet. The choice of below-grade water conductors would minimize surface area disturbance and eliminate the potential for penstock rupture that could produce surface discharge of water transported by those underground high-pressure pipelines between the upper reservoir and the powerhouse. In general, the water conductor and penstock alignments will seek to follow the most direct route between the upper reservoir and the powerhouse, taking into consideration areas topography and subsurface geotechnical conditions.

Below the powerhouse, the tailrace tunnel will also be bored with a TBM or drilled and blasted into and through the Eagle Mountains, with a finished diameter of 33 feet. Again, this would minimize surface area disturbance. Generally, the draft tubes and tailrace tunnel alignments will seek to follow the most direct route between the powerhouse and the lower reservoir, taking into consideration area topography and subsurface geotechnical conditions.

The penstocks, draft tubes and manifolds would be excavated using conventional drill and blast methods. The finished penstock diameter would be 15 feet and the finished draft tube diameter would be 17 feet.

Generally there are two types of reservoir intake structures for hydro-power projects, horizontal intakes and vertical drop intakes. The advantage of the vertical drop intakes ("morning glory" type) are that near maximum capacity is attained at relatively low heads. However, the disadvantage is that this type of inlet is ungated so that discharges from the upper reservoir cannot be stopped at the inlet in the event of an emergency. Horizontal intakes typically are gated by means of radial gates, slide gates, or an emergency bulkhead that can shut off water flow from the upper reservoir in the event of an emergency. For these reasons the intakes for the upper and lower reservoirs will be constructed horizontally.

The inlet/outlet structure at the upper reservoir will be located near the east end of the reservoir and will be constructed horizontally in the sloping bank of the pit. The inlet/outlet structure will use an approach channel and slope down to the tunnel invert. A fixed-wheel gate will be provided in the structure for emergency closure and for tunnel inspection. The inlet/outlet structure at the lower reservoir will be located near the west end of the reservoir and will be constructed horizontally in the sloping bank of the pit. The inlet/outlet structure will use an approach channel and slope down to the tailrace invert. A fixed-wheel gate will be provided in the structure for emergency closure and for tailrace inspection.

2.7 Unit Type Selection and General Arrangement

For many existing projects in the United States, and most recently proposed projects worldwide in the head range and project size at Eagle Mountain, the use of reversible, single-stage Francis units has been preferred over the use of separate pumps and turbines. Variable speed units are becoming more common because of their importance to realizing the ancillary benefits of pumped storage and their ability to pump over wide load variations. The generating head range of 1560 to 1251 feet at Eagle Mountain is well within the range of these types of units. Similarly, the nominal unit size of 325 MW is within the size range having a demonstrated history of reliable operating experience in the U.S. and overseas. For example, the reversible units at the Bath County Project in Virginia (operational since 1985) are rated at 350 MW. At the Rocky Mountain Project in Georgia (operational since 1995) the units are rated at 283 MW and at the Raccoon Mountain in Tennessee Project (operational since 1978) the units are rated at 383 MW.

The powerhouse arrangement is based on vertical-shaft units, with the turbine inlet valves and the draft tube gates located within the main powerhouse cavern. A separate cavern downstream of the main powerhouse cavern would house the power transformers, which increase voltage from 18 kV to 500 kV. A lay-down and erection area is provided at one end of the unit bays with direct access to the access tunnel. A service and controls bay is provided adjacent to the erection area.

2.8 Powerhouse Access

Access to the site is planned via Kaiser Road and from there to branch access roads, which lead to the various project features.

The normal access to the powerhouse will be through the main access tunnel. Its portal will be located at the ground surface on the northeast rim of the East Pit at El. 1100 from which it will extend 6,600 feet to the powerhouse floor at El. 837.

The alternative of access by a shaft directly above the powerhouse was considered. However, the powerhouse will be directly below the proposed landfill, which will, if constructed, ultimately place over 200 feet of fill depth over the ground surface above the powerhouse. The potential disruption of the landfill operations as well as access to the powerhouse ruled out the shaft access option. Secondary and emergency personnel access to and from the powerhouse will be from a shaft and short tunnel segment, with the shaft day-lighting in an area that is outside of the landfill to the north and west of the powerhouse location.

3 Plant Operations and Control

3.1 Mode of Operation

The basic mode of operation for the Project will be typical of most pumped storage projects: storing low-cost energy for use to provide peaking generation during periods of high power demand. In addition, this project will provide a range of ancillary grid operations services considered by the CAISO to be essential to integrating renewable energy generation sources such as wind and solar power. This pattern would use the available, unused capacity of wind and solar generation at night and on weekends, for energy to pump water from the lower reservoir to the upper reservoir. During the weekdays, and particularly during morning and afternoon peak demand periods the Project would operate as a hydroelectric generation project, releasing water from the upper reservoir through the reversible turbines to the lower reservoir to generate power. Power would also be generated as needed by the CAISO for voltage regulation, and load following, and would be available for spinning reserves.

The Project, with a cycle efficiency of 80 percent would use approximately 1.25 kWh of low cost energy to produce 1.0 kWh of much higher value energy in a different time period. A portion of the on-peak generation will offset the use of fossil fuel (mainly natural gas) for meeting peaking requirements. In addition to the straightforward use of a pumped storage project to provide on-peak generating capacity, the flexible operating characteristics of a pumped storage facility allow it to provide additional dynamic and ancillary benefits that can be quantified and priced. Two of the significant benefits are the ability of pumped storage to provide voltage regulation and load-following generation, almost instantaneously responding to changes in the system load by accepting or shedding the rapidly changing part of the load. When operating as a part of a thermal-based system, this characteristic coordinates well with the slower ramping rates of thermal units, which cannot efficiently respond as quickly or as efficiently to load changes. Other dynamic benefits include its ability to provide standby capacity, load and frequency control, and system reactive compensation, as well as black start capability.

3.2 Control

Operators in the powerhouse control room will staff the plant and be available to perform manually required monitoring, maintenance and operations as conditions dictate. Operation will be semi-automatic, entailing the initiation of controlled operations through the supervisory control equipment on the control switchboard or a remote control station. The equipment will respond by automatically performing such functions as startup, loading, unloading, synchronizing and shutdown and, in the pumping mode, draft tube depression, startup synchronizing, pump prime, loading, unloading, and shutdown. The plant will respond automatically to load dispatching instructions to start up or shut down from a remote control center. Monitoring data will be displayed locally and remotely as appropriate.

4 Dependable Capacity and Energy Production

As a peaking, voltage regulation, and load-following facility, the plant will normally operate for periods of several hours during weekdays of the peak generating season and shorter periods of rapid load change for load following and voltage regulation benefits during other periods of the week and year. Based on typical projects elsewhere in the U.S. an average annual capacity factor of 20 percent would be expected. However, the project has been sized with 18.5 hours of energy storage and could support a higher capacity factor. The annual energy production by the plant will similarly depend upon the way it is operated and the peak energy demands being met.

The rated generating capacity of the plant would be 1,300 MW. The generating capacity of the units is limited by the full-gate power produced by the turbines at a given head or by the continuous generating capacity of the motor/generators. The motor rating for pumping will be selected based upon the pumping capacity of the pump/turbines at the minimum pumping head. The plant operation is not dependent upon stream flow; therefore, the operation and plant capabilities are unchanged in adverse, mean, and high flow water years.

The level of the lower reservoir is the tailwater level in the generating cycle. As the upper reservoir level lowers during generation, the tailwater level will rise so that the available head and the full-gate turbine-generator output will vary with time.

5 Reservoir Operations

5.1 Reservoir Filling and Makeup Water Supply

The reservoirs will be filled with water from nearby wells in the Chuckwalla Basin. ECE is acquiring land and related water rights for the groundwater supply. Pipelines will deliver the water from the wells to the lower reservoir. Reservoir losses consist of evaporation and seepage. Evaporation is estimated based on an annual lake evaporation of 90 inches (7.5 feet) and the average lake surface areas provided in Table 5-1.

Table 5-1: Evaporation Estimate

Approximate Altitude (feet, msl)	Area (acres)	Estimated Lake Evaporation (ft/yr)	Annual Make up (AF/yr)
900 (Lower Reservoir)	121	7.5	908
2400 (Upper Reservoir)	114	7.5	855
Total			1,763

Average rainfall is cited as approximately 3 inches per year. The only rainfall affect on the reservoirs would be the rain that falls directly into the reservoirs, which is an average of 60 acre-feet per year (AFY) (3 inches on 235 acres). Despite efforts to effectively eliminate seepage, some recoverable losses are expected to occur. With these measures in place, a conservative allowance of 1600 AFY has been made for the seepage losses. A system of monitoring and seepage recovery wells has been designed to monitor groundwater levels and water quality, and return water lost to seepage to the lower reservoir.

The reservoir seepage losses will be replaced by water from the seepage recovery well(s). Water lost to evaporation will be replaced by water from the wells in the Chuckwalla Valley. The total amount of replacement water is conservatively estimated to be 1,703 AFY.

5.2 Reservoir Area-Capacity Curves

The area-capacity curves for the upper and lower reservoirs are presented in Figure 9-1, for the Central Pit Reservoir, and Figure 9-2 (Section 9) for the East Pit Reservoir.

5.3 Hydraulic Capacity of the Power Plant

The hydraulic capacity of the plant at maximum head is estimated to be 11,600 cfs (2,900 cfs per unit).

5.4 Power Plant Capacity vs. Head

At maximum gross head (1,560 feet), each of the 4 units will produce 325 MW in the generating mode with discharge of 2,900 cfs. At minimum gross head of 1251 feet, turbine output would be approximately 275 MW. Figure 9-3 (Section 9) shows the typical weekly operating cycle for the project.

6 Power Needs and Project Utilization

6.1 Power Needs

The following is an excerpt from the California Energy Commission 2007 Integrated Energy Policy Report, CEC-100-2007-008-CMF:

> "Statewide annual peak demand is projected to grow, on average, 850 megawatts per year for the next 10 years, or 1.35 percent annually. Population growth in California's drier, warmer areas increases peak demand more than it increases annual energy consumption. Another reason for the higher growth rate of the peak demand forecast compared to the electricity consumption forecast is the forecast's assumption that the 2005 federal air conditioning standards have no impact on peak because they result in little, if any, savings during the hottest hours when California peak demand occurs.
>
> The growth in peak demand is somewhat offset by projected increases in the electricity provided by self generation, reflecting the effects of the California Solar Initiative, the New Solar Homes Partnership, and the Self-Generation Incentive Program. The peak demand forecast represents the net amount of load the electric grid must serve so that demand by self generation reduces the electric system peak. In the forecast, the growth in photovoltaic and other self-generation installations is assumed to reduce peak demand by 650 megawatts by 2018, based on current costs and program performance. If the installed cost of photovoltaic systems declines significantly, either through reductions in component or installation costs or increases in federal/state tax credits, this projection could easily be exceeded.
>
> In the entire Central Valley and desert regions of the state, demand is projected to increase by 5,500 megawatts during the forecast period. Forty percent of this (2,200 megawatts) is in the Inland Empire area served primarily by Southern California Edison (SCE) and Riverside Public Utility. The remaining, 2,300 megawatts, is growth in the Central and Sacramento Valley areas, served by Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD), and other utilities. Projected electricity demand growth, while doubling, is noticeably less in the more developed coastal areas served by PG&E and SCE than it is in the valley/desert areas."

Figure 9-4 in Section 9 was taken from the above-mentioned report and shows the tremendous growth in peak electrical demand in Southern California expected to occur between 2012 and 2018. This is the timeframe during which the Eagle Mountain Pumped Storage Project will be coming on-line.

In November 2007, CEC prepared the California Energy Demand 2008-2018 Staff Revised Forecast. Chapter 3 of that report deals with the SCE Planning Area, which includes: 1) SCE bundled retail customers, 2) customers served by energy service providers (ESPs) using the SCE distribution system to deliver electricity to end users, and 3) customers of the various Southern California municipal and irrigation district utilities, excluding the cities of Los Angeles, Pasadena, Glendale, and Burbank and the Imperial Irrigation District. Forecasted energy consumption and peak loads for the SCE planning area, including both total and per capita values, are presented.

Forecasts for the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI) and estimates of conservation savings are also provided.

Table 6-1 from that report compares the revised electricity consumption forecast with the draft 2008-2018 forecast and 2006 forecast. The revised forecast is higher than both of the previous forecasts over the forecast period and by 2018, the revised forecast is about 2.5 percent higher than the draft forecast and 4.5 percent higher than the 2006 forecast. This results from incorporation of the new Department of Finance (DOF) long-term population projections. DOF raised its projection of population in the SCE planning area, particularly in the hotter Inland Empire region of the planning area. Table 5-2 presents a similar comparison for the peak demand forecasts. The increase in peak demand of the revised forecast is driven by the underlying changes in the energy consumption forecasts. The increase in the 2008–2016 growth rate of the revised forecast compared with the previous two forecasts is primarily driven by the revised DOF population forecast used in the revised forecast. The Table 5-2 projections are shown in graphical format on Figure 9-5, which was taken from the CEC 2008-2018 forecasts.

Table 6-1: SCE Planning Area Energy Forecast Comparison

Consumption (GWH)					
	CED 2006	**Staff Draft**	**Staff Revised**	**Percent Difference Staff Revised/*CED 2006***	**Percent Difference Staff Revised/Staff Draft**
1990	81,579	82,069	82,069	0.60%	0.00%
2000	98,346	99,148	99,146	0.81%	0.00%
2005	99,531	99,136	99,261	-0.27%	0.13%
2008	103,437	105,106	105,054	1.56%	-0.05%
2013	109,931	112,064	113,815	3.53%	1.56%
2016	113,409	115,627	118,497	4.49%	2.48%
Average Annual Growth Rates					
1990-2000	1.89%	1.91%	1.91%		
2000-2005	0.24%	0.00%	0.02%		
2005-2008	1.29%	1.97%	1.91%		
2008-2016	1.16%	1.20%	1.52%		
Historic values are shaded					

Source: California Energy Commission, 2007

Table 6-2: SCE Planning Area Peak Forecast Comparison

Peak (MW)					
	CED 2006	**Staff Draft**	**Staff Revised**	**Percent Difference Staff Revised/*CED 2006***	**Percent Difference Staff Revised/Staff Draft**
1990	17,564	17,635	17,635	0.41%	0.00%
2000	19,465	19,408	19,408	-0.29%	0.00%
2005	21,510	21,956	21,956	2.07%	0.00%
2008	22,483	23,142	23,272	3.51%	0.56%
2013	24,059	24,674	25,258	4.98%	2.37%
2016	24,934	25,513	26,382	5.81%	3.40%
Average Annual Growth Rates					
1990-2000	1.03%	0.96%	0.96%		
2000-2005	2.02%	2.50%	2.50%		
2005-2008	1.49%	1.77%	1.96%		
2008-2016	1.30%	1.23%	1.58%		
Historic values are shaded					

Source: California Energy Commission, 2007

6.2 Power Utilization

The Eagle Mountain Project is anticipated to be on-line in 2015-2016 and will be available to assist in meeting the nearly 4,000 MW increase in peak demand over the next decade, as well as the ancillary services described above that are essentially to successful attainment of California's RPS goals of 33 percent by the year 2020, and concurrent related decreases in emissions of greenhouse gases.

6.3 Power Consumption

The maximum amount of pumping energy that could be consumed annually by the Project is in the range of 3,500 GWh, but will depend on how the project is operated to meet peak demands and how ancillary benefits are accessed and managed. ECE's station service load is expected to be negligible. The largest potential load associated directly with construction and operation of the Project will be for the reverse osmosis (RO) treatment system. Since the RO system will utilize head to run the membranous system, it will be more efficient than most desalinization plants that use electricity.

7 Plans for Future Development

The site has potential for adding capacity up to well over 1,300 MW, perhaps as much as 3,500 MW. This would require raising the upper reservoir dams and adding dams to fully contain a higher lower reservoir. Alternatively, the amount of storage could be kept the same as currently proposed (17,700 acre-feet) and the hours of generation decreased to support a higher installed capacity. Further development of the site up to its full potential may be considered by ECE in the future, depending on the performance of the currently proposed 1,300 MW development and the market for additional pumped storage capacity.

8 Literature Cited

California Energy Commission. (2007). California Energy Demand 2008-2018 Staff Revised Forecast. Staff Final Report. CEC-200-2007-015-SF2.

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9 Figures

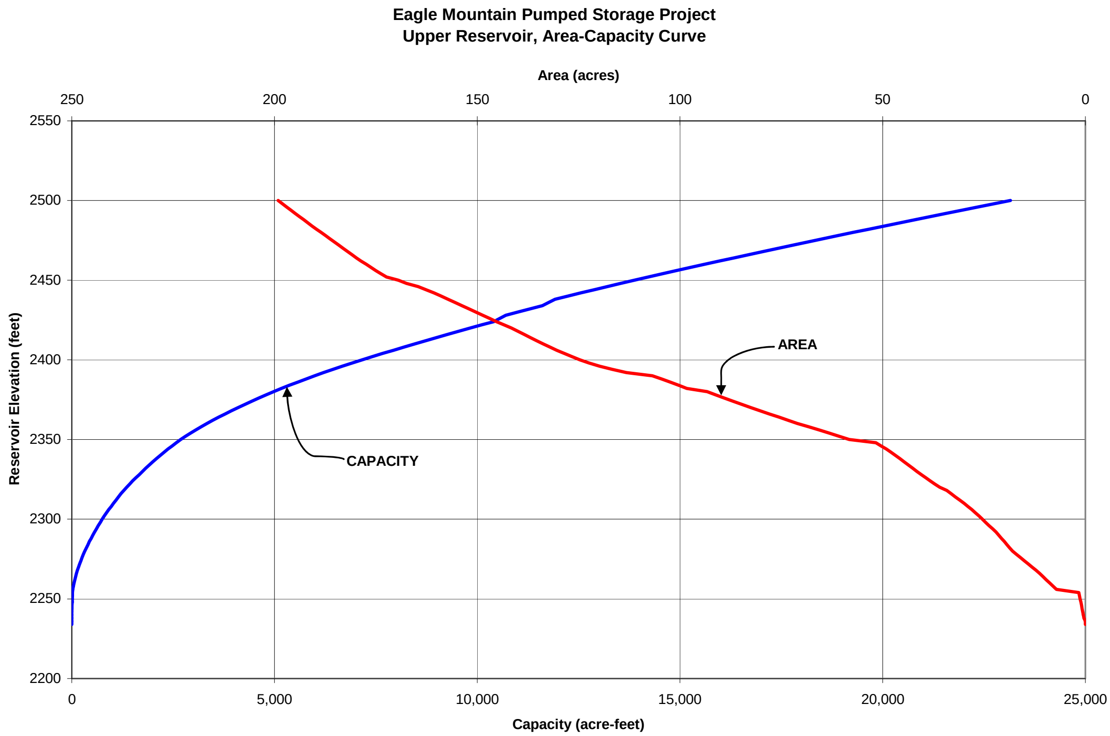

Figure 9-1: Upper Reservoir Area-Capacity Curve

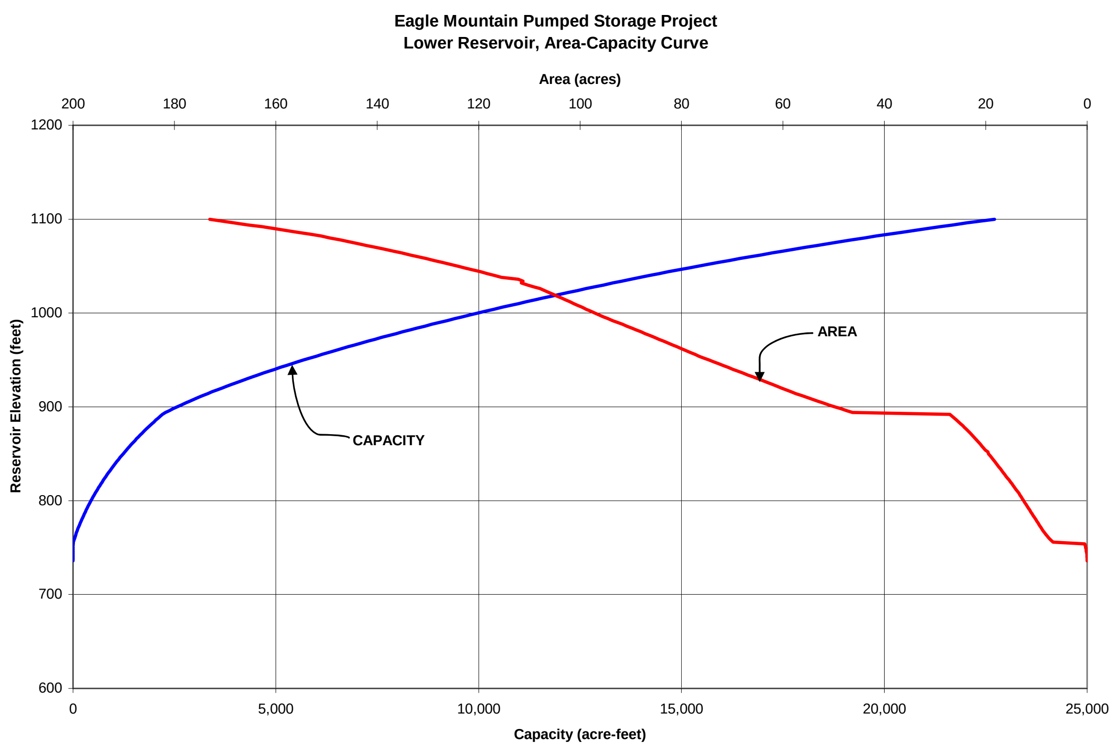

Figure 9-2: Lower Reservoir Area-Capacity Curve

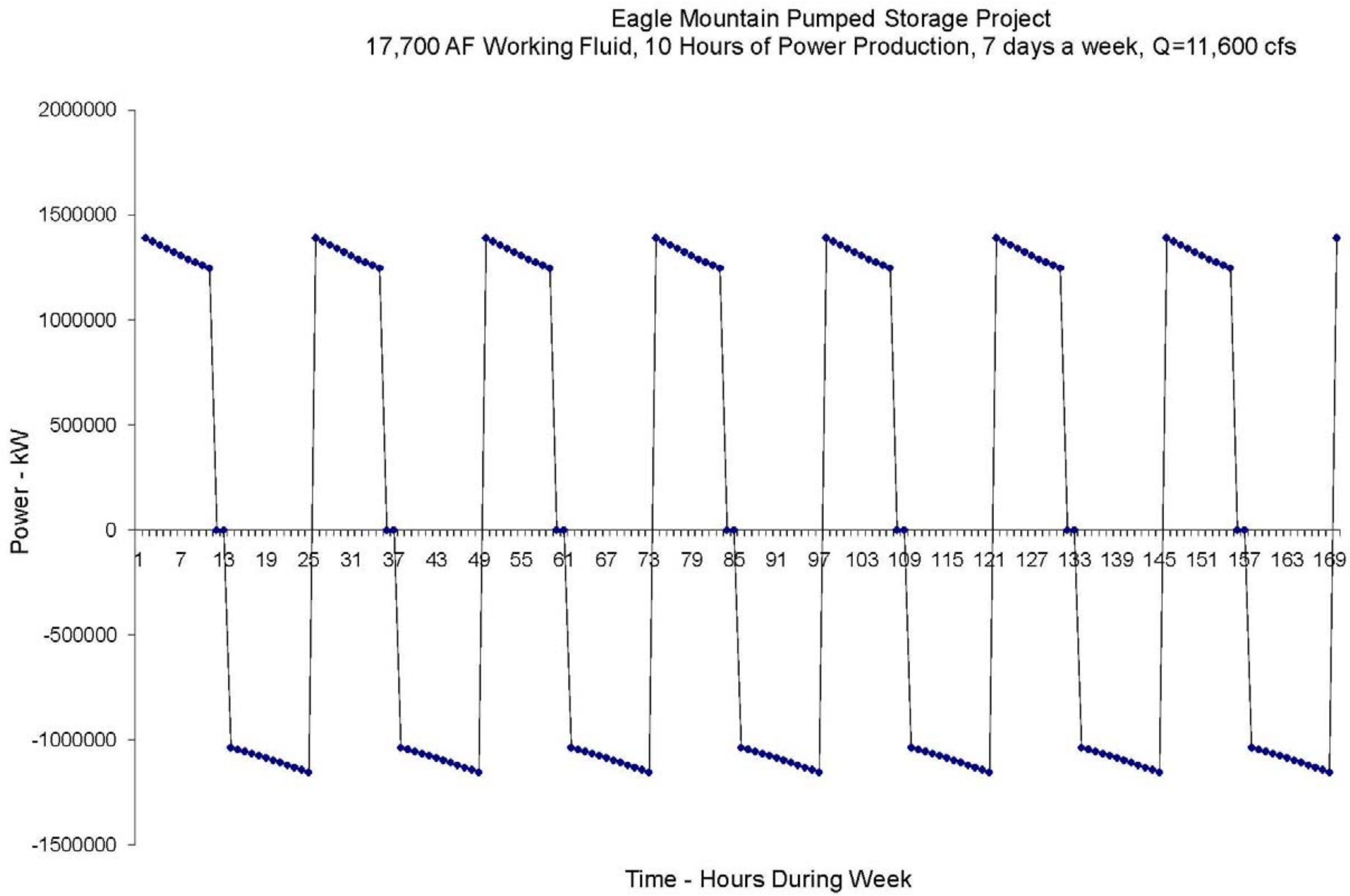

Figure 9-3: Typical Weekly Operation of the Eagle Mountain Pumped Storage Project

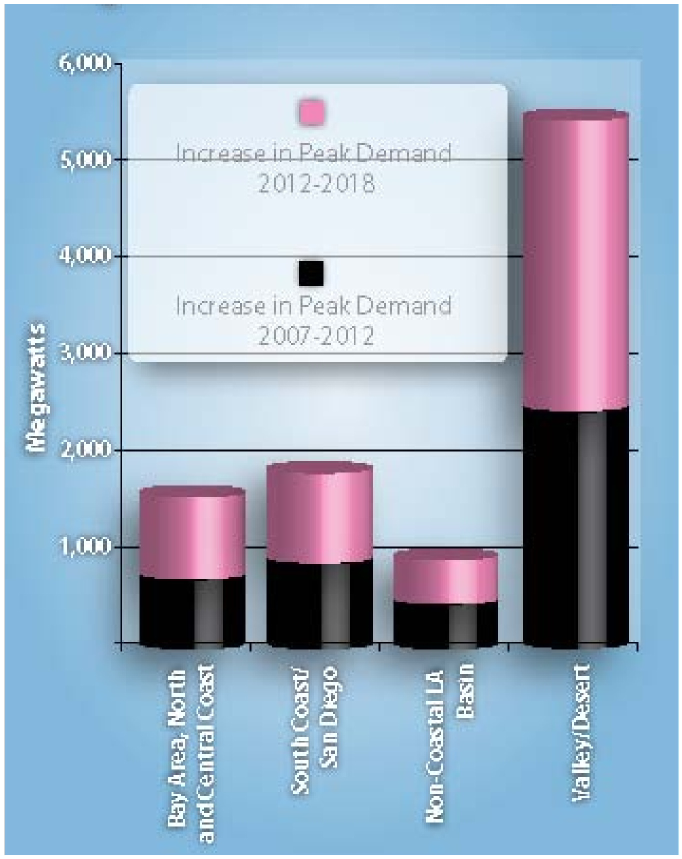

Figure 9-4: Regional Growth in Peak Demand. Source: California Energy Commission, California Energy Demand 2008–2018, CEC-200-2007-015-SF2.

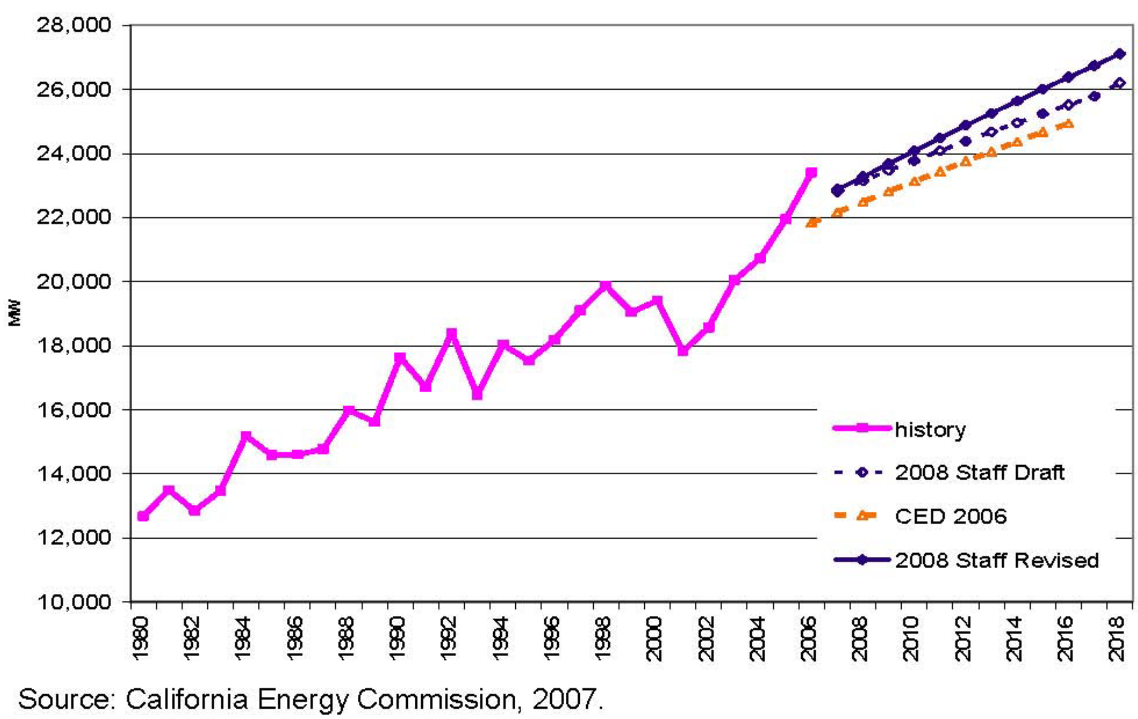

Figure 9-5: SCE Planning Area Peak Demand Forecast