Eagle Mountain Pumped Storage Project
Draft License Application

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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Project No. 080470

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Tables

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 production in the 1980s. The site is located near the Town of Eagle Mountain in Riverside County, CA, approximately 30 miles east of Indio, CA and 11 miles north of I-10 and the town of Desert Center.

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

- Two existing, abandoned 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 long dams. Thus this site offers 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 10 miles of a major electrical transmission line corridor, the Palo Verde to Devers corridor, which extends from the Palo Verde Nuclear Plant in Arizona to the Devers Substation near Palm Springs. The site is within 50 miles of a planned new substation in that same transmission corridor.

- The site is located close to potential sources of water to initially fill the reservoirs and to provide makeup water for evaporation and seepage. Sources include the Chuckwalla Valley Aquifer (groundwater) and the Colorado River Aqueduct (surface water).

- The site has potential to firm a growing regional portfolio of solar and wind power projects making them even more valuable to meet California's energy needs.

There are no other alternative sites for pumped storage development with the above-noted attributes. Therefore, no other sites have been considered by Eagle Crest Energy Company (ECE) for developing the proposed pumped storage project. In the past, ECE has considered the potential use of the west pit of the mine as a secondary upper reservoir for an expanded project. This option for expansion is not being proposed at this time.

1.2 Transmission Alternatives

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 50.5 miles. • Connection Point: A new substation/switching station at Eagle Mountain. • Connection Point: The Proposed Colorado River Substation adjacent to the existing Palo Verde-Devers 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 1,281 acres (does not include construction access roads).

Transmission Line Facilities (500 kV, single circuit)
• Conductors: One, three-phase AC circuit consisting of three 1.5 to 2-inch ACSR conductors per phase.
• Minimum Conductor Distance from Ground: 35 feet at 60°F and 32 feet at the maximum operating temperature.
• Shield Wires: Two 1/2 to 3/4-inch-diameter wire(s) for steel lattice.
• Transmission Line Tower Types:
  - Steel Lattice Tower along entire route.
  - Structure Heights (approximate): Steel Lattice – 100 to 180 feet.
• Average Distance between Towers: Steel Lattice – 1,200 feet.*
• Total Number of Towers (approximate): 225 – 265.*

Substation Facilities • A new substation/switching station at Eagle Mountain requiring a total area of approximately 25 acres would be constructed. • Colorado River Substation: Facilities would be expanded at the Proposed Colorado River Substation, Southwest of Blythe, California, to accommodate interconnection of the Proposed Project 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 exact quantity and placement of the structures depends on the final detailed design of the transmission line, which is influenced by the terrain, land use, and economics. Alignment options may also slightly increase or decrease quantity of structures.

The most favorable transmission line route has been determined to be one that interconnects the proposed Project switchyard to the proposed Colorado River Substation, which will be adjacent to the existing Palo Verde-Devers 500-kV line owned by Southern California Edison (SCE). The approximate length of this line is 50.5 miles. The length of the line may decrease by a few miles depending on the final selected location for the Colorado River Substation. The existing Palo Verde-Devers 500-kV line is under the operational control of the California Independent Systems Operator (CAISO) as part of the restructured California electrical utility industry.

The proposed routing from the Project was selected as the one that would most economically supply power to, and receive power from, the southwestern grid. A second 500 kV line to be constructed by SCE, and located in the same corridor as the existing line, is currently in the planning stage. Load-flow and other studies are required, and will be conducted, to determine whether or not the combined capacity from Palo Verde to Devers is adequate to accommodate the

1300 MW flow from the Project with an interconnection at the proposed Colorado River Substation.

On May 16, 2008, ECE submitted an Interconnection Request (IR) application for the Eagle Mountain Pumped storage Project to interconnect the generating facility to the CAISO electrical grid at the Southern California Edison's (SCE) proposed Colorado River Substation (previously named Midpoint Substation) as part of SCE's proposed Devers-Palos Verdes #2 (DPV2) transmission line project. The Colorado River Substation will also loop in the existing Devers-Palos Verdes #1 (DPV1) transmission line. On May 30, 2008, ECE was notified by the CAISO that it has determined the IR is valid and has the effective queue date of May 16, 2008.

The interconnection of the Project at the Colorado River Substation will most likely require the construction of the DPV2 transmission line to 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. However, the Arizona Corporation Commission (ACC) denied the necessary approvals for SCE to build in that state. 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.

SCE intends to seek authority from the CPUC to phase DPV2 construction by moving forward with California facilities first. This will include construction of a new "Colorado River (Midpoint) Substation" near the California/Arizona border that will loop in the existing DPV1 transmission line and provide the interim terminus for the DPV2 line. SCE's decision to move forward with the new substation and the California facilities will allow the Eagle Mountain Project to have access to the California market. The new substation with the looped-in existing DPV1 transmission line should be sufficient to allow the Project to access the Arizona and Nevada markets. These assumptions will be validated by the CAISO and the TO during a June 2008 scoping meeting and the interconnection studies.

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, peaking generation with load following capability resources will be an essential part of the Western region's generating resource mix.

1.3 Water Supply Alternatives

The alternatives for supply of the initial filling and for water to make up for evaporation and seepage are limited. The Project is not located on a natural stream nor would the small 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 Metropolitan Water District's (MWD) Colorado River Aqueduct (CRA). ECE is reviewing the alternatives to determine the economic feasibility and environmental impacts of each. One option is to fill the required storage initially using ground water and to rely on ground water for makeup water supplies as well. A rather large aquifer in the Chuckwalla Basin is located near the Project. Existing wells in the Chuckwalla Basin in earlier years supplied the mining operations at Eagle Mountain and supported more extensive agricultural irrigation use than exists now. Studies indicate that groundwater obtained by purchasing existing wells could be used as an initial filling source and for make-up water for the project, without causing ground water levels to be drawn down below historic levels attained during a previous period of heavier ground water withdrawals when jojoba production was at its peak in the Chuckwalla Basin.

Depending on costs, availability, environmental impacts and other factors, ECE may negotiate for a supply that could be obtained from the CRA as a "one-time" source for initial filling. This would require a purchase of water from a willing seller and "wheeling" the water to obtain a supply at the CRA. In this scenario, ground water could be used to provide the make-up water supplies.

ECE is investigating the option to purchase water from a third party and deliver that water to MWD. In exchange, MWD would provide the same amount of water at the Colorado River Aqueduct. This arrangement has been discussed with MWD staff. The MWB Board would need to approve of any such wheeling or exchange agreement. Potential sources of water supply for the proposed exchange will most likely come from the purchase of surplus water in the San Joaquin 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.

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, made the choice of a surface powerhouse uneconomical in comparison with the underground location. An underground powerhouse could be constructed closer to the lower reservoir; however, this arrangement would involve a longer high-head tunnel and there would be 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 Eagle Mountain site could accommodate up to about 4,900 MW of capacity with the same arrangement of waterways and a powerhouse between the Central and East Pit Reservoirs. However, major dams would be required to create the upper reservoir, as well as significant dams to impound the upper portion of the lower reservoir. Staging studies indicated that an initial installed capacity of 1,000 to 1,500 MW could be economically engineered to enable a future doubling of capacity. The selected installed capacity of 1,300 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. Decisions will be made during the preliminary design phase of Project implementation about whether or not to design and build the project initially in order to enable a more-economical future expansion. This would include over-sizing the tunnels and reservoir I/O structures, as well as additional foundation treatments at the dams.

2.3 Storage Capacity

The storage capacity of the reservoirs is directly connected 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 9 hours during each weekday while pumping back for a period of 8 hours each weekday night (the Independent System Operator and Palo Verde Nuclear

Generating Station off-peak periods are from 10:00 PM to 6:00 AM). Pumping would be required during weekends to makeup water not returned to storage during weekdays. This requires a working volume of 17,700 acre-feet. The resulting maximum weekly energy production with the indicated pump-back cycle is approximately 53,900 MWh. Shorter and longer generating periods may be considered during further investigations. The 9-hour generating period was selected because it provides flexibility in Project operations.

2.4 Upper Reservoir

Early studies in the 1990s considered the possibility of using the Black Eagle Pit as the upper reservoir instead of the Central Pit. However, this alternative was considered only in conjunction with concurrent use of the Central Pit for a much larger Project capacity, because the Black Eagle Pit is a greater distance from the East Pit, which in all cases would be the lower 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 and to allow for possible future expansion.

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 preliminary 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 or using materials generated from tunnel and underground structure excavations. The final decision on type of dam will be based on further studies and 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 1300 MW project (21,900 acre-feet). Therefore, no dam structures are needed at the lower reservoir. With the invert of the I/O structure at El. 925 feet, there are approximately 4,200 acre-feet of inactive storage. The operating levels of the lower reservoir, between El. 925 and El. 1092, were selected in conjunction with those of the upper reservoir to maintain the operating head of the pump/turbines in an acceptable range and to allow possible expansion without significantly changing the operating head. For the 1,300 MW project, the available storage in the lower reservoir will be sufficient without having to construct containment dams along the reservoir rim.

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

The water conductor and penstocks 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 Mountains, with finished diameters of 29 feet and 15 feet, respectively. This would minimize surface area disturbance and reduce or 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 the area's topography and subsurface geotechnical features.

Below the powerhouse, the draft tubes and tailrace tunnel will also be bored with a TBM or drilled and blasted into and through the Eagle Mountains, with finished diameters of 17 feet and 33 feet, respectively. 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 the areas topography and subsurface geotechnical features.

Generally there are two types of intake structure, horizontal intakes and vertical drop intakes. The advantage of the vertical drop intakes are that near maximum capacity is attained at relatively low heads. However, the disadvantage is that the inlet is ungated so 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. Because of 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, in the head range and project size at Eagle Mountain, the use of reversible, variable speed, single-stage Francis units has been preferred over the use of separate pumps and turbines. 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. The reversible units at the Bath County Project (operational since 1985) are rated at 350 MW. At the Rocky Mountain Project (operational since 1995) the units are rated at 283 MW and at the Raccoon Mountain 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 large shaft 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.

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. This pattern would use the available, unused capacity of wind generation and base-loaded thermal plants at night, and on weekends, for energy to pump water from the lower reservoir to the upper reservoir. During the weekdays, and particularly during the late afternoon and evening, 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.

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. The annual plant capacity factor (ratio of average annual output to installed capacity) will be in the range of 20 to 27%.

In addition to the straightforward use of a pumped storage project to provide economical generating capacity, the flexible operating characteristics of a pumped storage facility allow it to provide additional dynamic benefits. One of the significant benefits is the ability of pumped storage to provide 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 quickly 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. The CAISO purchases these ancillary services.

3.2 Control

Operators in the powerhouse control room will normally 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 and load following facility, the plant would normally operate for periods of several hours during weekdays of the peak generating season and shorter periods of rapid load change for load following 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% would be expected. However, the project has been sized with 18.5 hours of energy storage and could support a higher capacity factor on the order of 26 to 27%. 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 1300 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 either be filled with water from wells in the nearby Chuckwalla Basin or from surface water purchased from willing sellers elsewhere and transferred to the Project through the Colorado River Aqueduct. If groundwater is used, pipelines will deliver the water from the wells to the lower reservoir. Reservoir losses consist of evaporation and seepage. Evaporation estimates were based on a simple analysis that will be made much more rigorous during final design. Evaporation is estimated based on an estimated 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

Approx. Altitude (feet, msl)	Area (acres)	Est. 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. Allowing the rainwater to flow into the reservoirs would require a change in the Regional Water Quality Control Board Orders for the Landfill, which prescribes that the waters be spread out in non-erosive flows across the desert rather than be collected. The only rainfall affect on the reservoirs would be the rain that falls into the reservoirs, which is an average of 60 acre-feet per year (AFY) (3 inches on 235 acres). Therefore, the makeup requirement for evaporation would be approximately 1,700 AFY.

Despite efforts to effectively eliminate seepage, some losses are expected to occur. With these measures in place, a conservative allowance of 600 AFY has been made for the seepage losses.

The reservoir losses will be replaced by water from the nearby wells. The total amount of replacement water is estimated to be 2300 AFY.

5.2 Reservoir Area-Capacity Curves

The area-capacity curves for the upper and lower reservoirs were presented in Figure B.5-1, for the Central Pit Reservoir, and Figure B.5-2 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 (2900 cfs per unit).

5.4 Power Plant Capacity vs. Head

Relationships between gross operating head, net head, and pump input and turbine output will be developed during subsequent phases of project design and implementation. In addition to conventional fixed-speed equipment, ECE will be examining the benefits and cost tradeoffs associated with using variable-speed pump-turbine units. For planning at this time and preliminary characterization of project costs and benefits, typical relationships between head, discharge and efficiency for large reversible pump-turbine units have been assumed. At maximum gross head (1560 feet), each of the 4 units was assumed to 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 B.5-3 shows the typical weekly operating cycle for the project with maximum output for 1300 MW.

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."

The following figure (Figure B.6-1) 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 6-2 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 6-2 projections are shown in graphical format on Figure B.6-2, 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%

Peak (MW)					
	CED 2006	Staff Draft	Staff Revised	Percent Difference Staff Revised/*CED 2006*	Percent Difference Staff Revised/Staff Draft
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 and will be available to assist in meeting the nearly 4000 MW increase in peak demand over the next decade.

6.3 Power Consumption

The amount of pumping energy consumed annually by the Project is in the range of 3,500 GWh per year, but will depend on how the project is operated to meet peak demands. 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 RO treatment system. Since the RO system will utilize head to run the membranous system, it will be more efficient that most desalinization plants that use electricity.

7 Plans for Future Development

The site has potential for adding capacity up to well over 1300 MW, perhaps as much as 3500 MW. This would require raising the upper reservoir dams and adding dams to fully contain a higher lower reservoir. Further development of the site up to its full potential may be considered by ECE, depending on the performance of the currently proposed 1300 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 B.5-1. Upper Reservoir Area-Capacity Curve

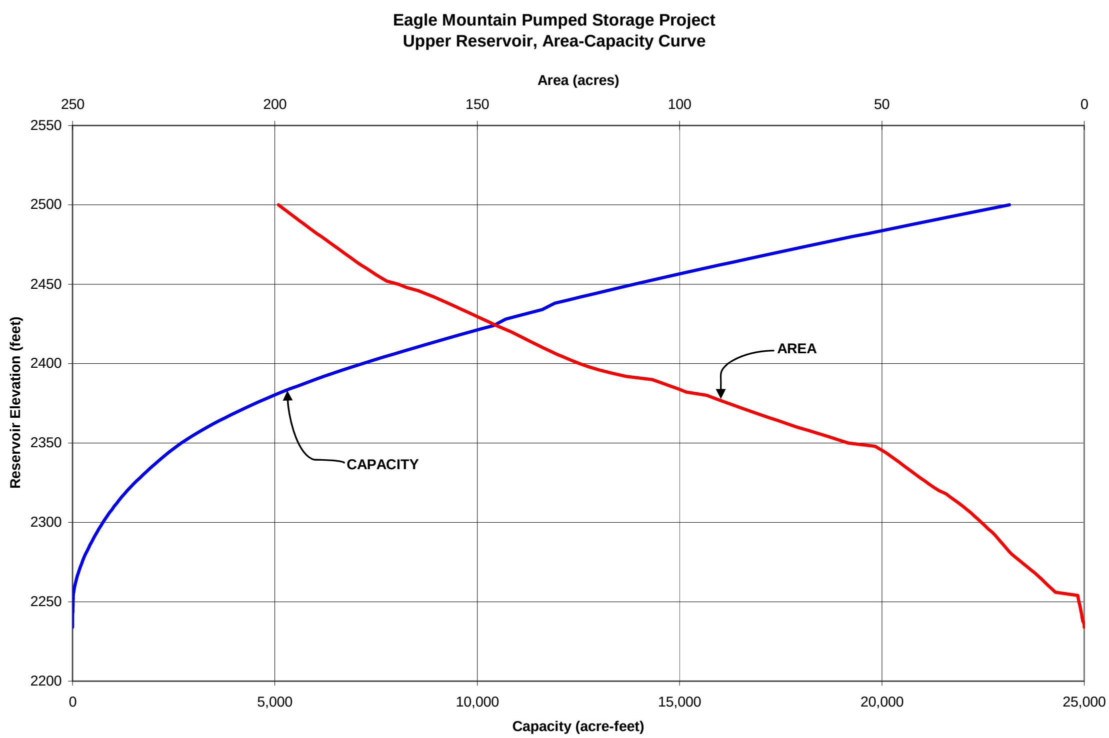
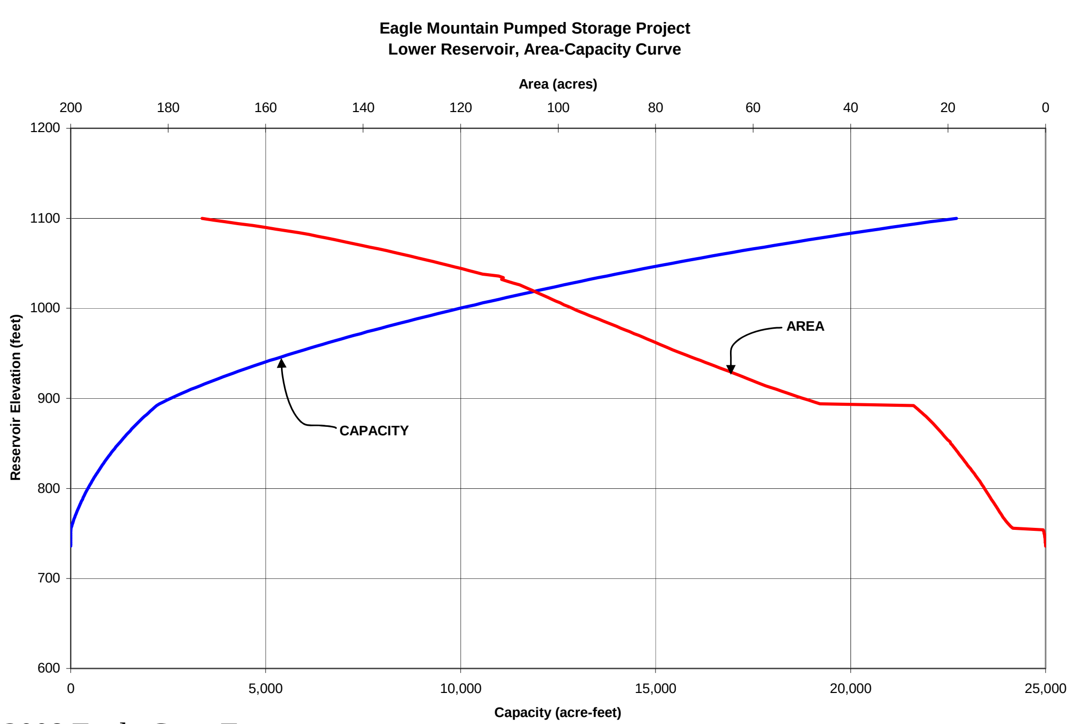
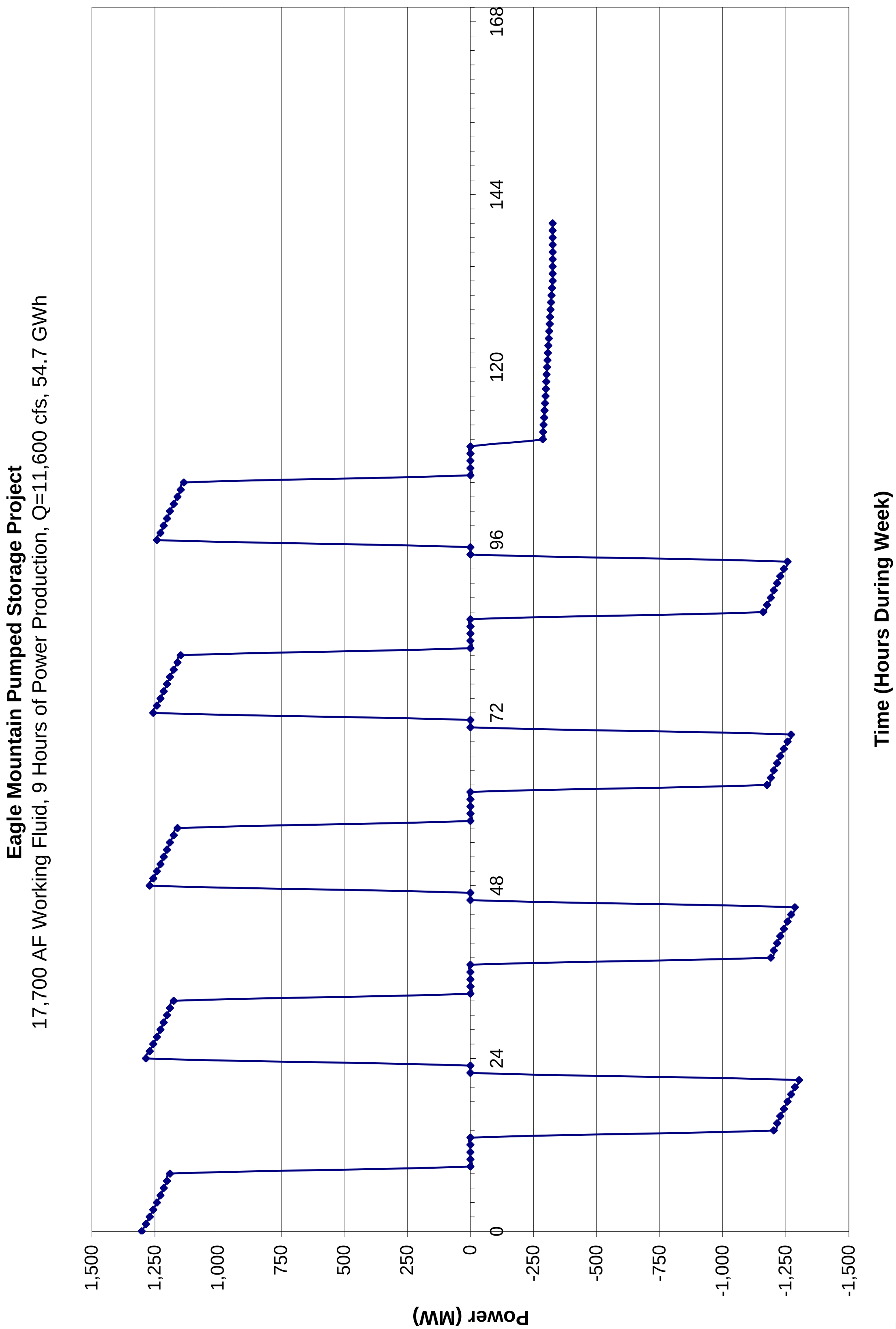


Figure B.5-2. Lower Reservoir Area-Capacity Curve





B.1.

Figure B.5-3. Typical Weekly Operation of the Eagle Mountain Pumped Storage Project

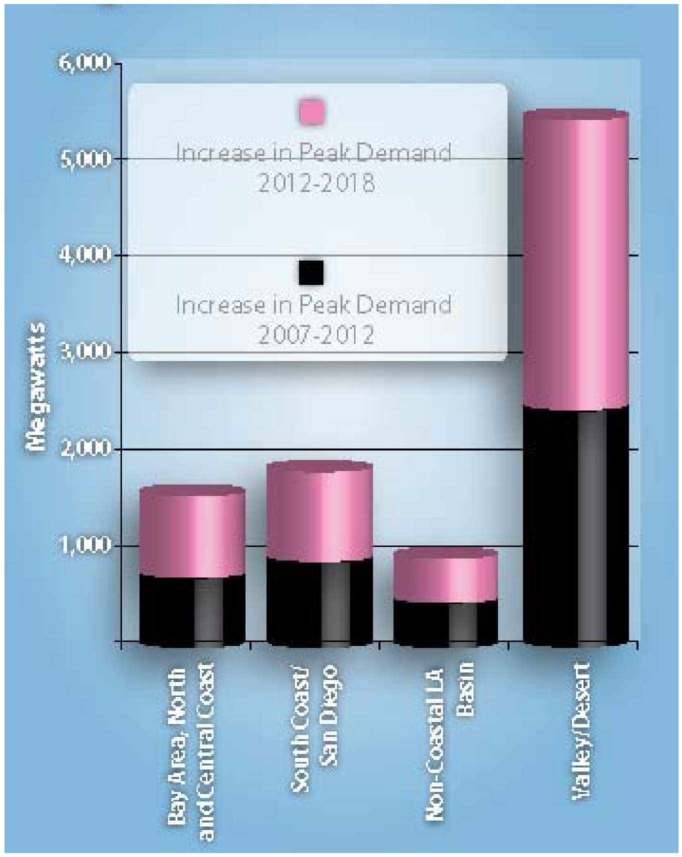
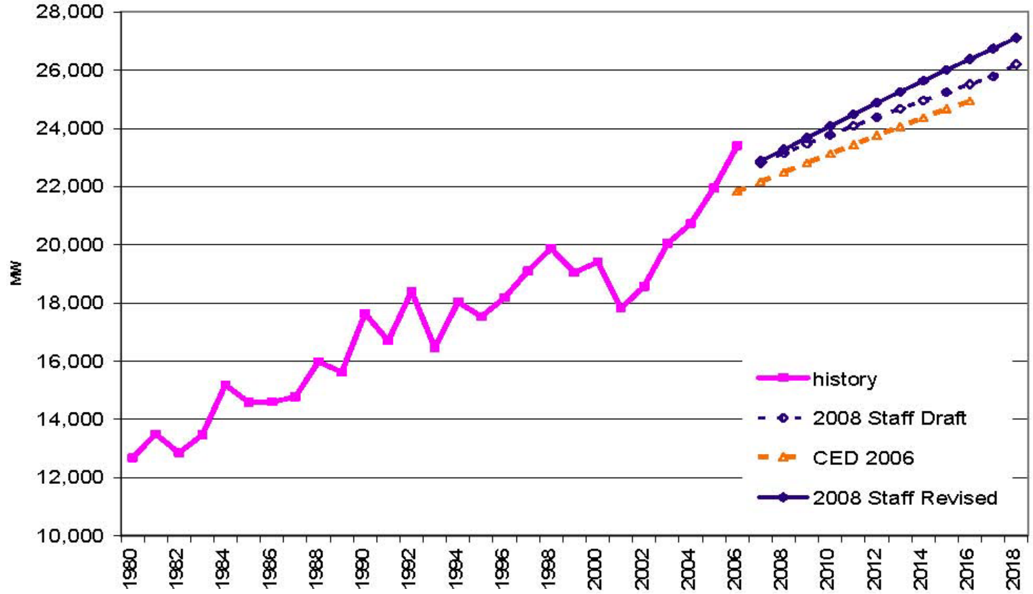


Figure B.6-1. Regional Growth in Peak Demand

Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-2002007-015-SF2.

Figure B.6-2. SCE Planning Area Peak Demand Forecast



Source: California Energy Commission, 2007.