Initial Statement

SOUTHERN CALIFORNIA EDISON COMPANY
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company P-2175

APPLICATION FOR LICENSE FOR MAJOR PROJECT–EXISTING DAM

1. Southern California Edison Company (SCE or Applicant) applies to the Federal Energy Regulatory Commission (Commission) for a new License for the Big Creek Nos. 1 and 2 Hydroelectric Power Project (Project), as described in the attached exhibits. The existing Project is designated as Project No. 2175 in the records of the Commission, pursuant to a License issued by the Commission on March 27, 1959, and effective on March 1, 1959, for a period of 50 years from the expiration date of the prior long-term license, and terminating on February 28, 2009. This Application For New License for Major Project – Existing Dam is filed pursuant to 18 CFR §§ 4.51 and 16.9.

2. The location of the project is:

   State: California
   County: Fresno County
   Nearby Town: Big Creek
   Stream(s): Big Creek

3. The exact name and business address of the applicant are as follows:

   Southern California Edison Company
   Attention: Nino J. Mascolo
   Senior Attorney
   P.O. Box 800
   Rosemead, California 91770
   (626) 302-4459

The exact name and business address of the person authorized to act as agent for the Applicant in this Application is

Russ W. Krieger
Vice President, Power Production
Southern California Edison Company
300 N. Lone Hill Avenue
San Dimas, CA 91773
(909) 394-8667

4. The Applicant is a domestic corporation. No municipal preference exists under section 7(a) of the Federal Power Act for this existing licensed Project.

5(i). The statutory or regulatory requirements in California, the state in which the Project is located, that affect the Project with respect to the bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act are:

California Water Code Section 1200, et seq.; Title 23 California Code of Regulations Section 650, et seq., permits an application to be filed with the California Water Resources Control Board to obtain a permit or license to appropriate water, which is otherwise declared unappropriated, for beneficial uses including power uses.

California Water Code Section 13160; Title 23 California Code of Regulations Section 3855, regulates the federally required filing of applications for water quality certification with the California Water Resources Control Board.

Public Utilities Code, Section 201, et seq., regulates the right of the public utility to produce, generate, transmit, or furnish power to the public.

5(ii). The steps which the Applicant has taken or plans to take to comply with each of the laws cited above are:

Applicant has either obtained the necessary permits and licenses or otherwise acquired water rights by appropriation and/or prescription for use of Project water.

Licensee will file an application for a water quality certificate or waiver thereof with the California Water Resources Control Board in accordance with applicable state law and the Commission's regulations.

The California Public Utilities Commission has authorized SCE to produce, generate, transmit, or furnish power to the public.

6. The Applicant is the owner and existing licensee of the Project. The dam associated with the Project is not federally owned or operated.

Date: 2/21/07

By: ______________________
Russ W. Krieger
Vice President, Power Production

VERIFICATION

This Application For New License For Major Project – Existing Dam is executed in the

STATE OF CALIFORNIA
CITY OF SAN DIMAS
COUNTY OF LOS ANGELES

By: Russell W. Krieger
Vice President, Power Production
Southern California Edison Company
300 N. Lone Hill Avenue
San Dimas, California 91773

Russell W. Krieger, being first duly sworn, deposes and says: that he is a Vice President of Southern California Edison Company, the Licensee making the Application for New License for the Big Creek Nos. 1 and 2 Hydroelectric Power Project (FERC Project No. 2175); that the contents of this Application are true to the best of his knowledge and belief. The undersigned Applicant has signed the Application this 21st day of February, 2007.

RW Krieger
Russell W. Krieger
Vice President, Power Production

State of California
County of Los Angeles

On Feb. 21, 2007 before me, Lisa A. Smith, Notary Public personally appeared Russell W. Krieger, personally known to me to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

Witness my hand and official seal.

Lisa A Smith
Notary Public

LISA A. SMITH
Commission # 1712414
Notary Public - California
Los Angeles County
MyComm. Expires Dec 23, 2010

Section 4.32 General Information

This section of the Application for New License for the Project is intended to set forth the information required by 18 C.F.R §4.32, as follows:

a) Each applicant must:

(1) For a preliminary permit or license, identify every person, citizen, association of citizens, domestic corporation, municipality, or state that has or intends to obtain and will maintain any proprietary right necessary to construct, operate, or maintain the project;

(2) For a preliminary permit or a license, identify (providing names and mailing addresses):

(i) Every county in which any part of the project, and any Federal facilities that would be used by the project, would be located:

(ii) Every city, town, or similar local potential subdivision:

(A) In which any part of the project, and any Federal facilities that would be used by the project, would be located; or

(B) That has a population of 5,000 or more people and is located within 15 miles of the project dam;

(iii) Every irrigation district, drainage district, or similar special purpose political subdivision:

(A) In which any part of the project, and any Federal facilities that would be used by the project, would be located; or

(B) That owns, operates, maintains, or uses any project facilities or any Federal facilities that would be used by the project;

(iv) Every other political subdivision in the general area of the project that there is reason to believe would likely be interested in, or affected by, the application; and

(v) All Indian tribes that may be affected by the project.

(1) To the knowledge of Southern California Edison Company (SCE), no person, citizen, association of citizens, domestic corporation, municipality, or state, other than SCE has or intends to obtain any proprietary right necessary to construct, operate, or maintain the Project.

(2) (i) All Project boundaries and facilities are located in the County of Fresno, which has its principal administrative office located at:

Fresno County
Board of Supervisors
2281 Tulare Street, Room 301
Fresno, CA 93721

(ii) None of the Project boundaries or facilities are located within any city, town, or other similar local political subdivision. There are no communities of 5,000 or more people located within 15 miles of the Project.

(iii) There are no irrigation districts, drainage districts, or other similar special purpose political subdivisions located within the Project area or which own, operate, or maintain any Project facilities. The Project does not use any federal facilities.

(iv) The following political subdivisions or nonpolitical organizations in the general area of the Project may be interested in the application:

Shaver Lake Chamber of Commerce
P.O. Box 58
Shaver Lake, CA 93664

North Fork Chamber of Commerce
P.O. Box 426
North Fork, CA 93643

North Fork Community Development Council
P.O. Box 1484
North Fork, CA 93643

Sierra Unified School District
31795 Lodge Road
Auberry, CA 93602

Big Creek Elementary School District
55190 Point Road
Big Creek, CA 93605

Pine Ridge Elementary School District
45828 Auberry Road
Auberry, CA 93602

Chawanakee School District
P.O. Box 400
North Fork, CA 93643

Toby Horst
Director, Sierra Resource Conservation District
36281 Lodge Road
Tollhouse, CA 93667

(v) The Federally recognized Indian tribes and other Indian organizations that may be affected by, or interested in, the Project include:

Big Sandy Rancheria*
P.O. Box 337
Auberry, CA 93602

Cold Springs Rancheria*
P.O. Box 209
Tollhouse, CA 93667

North Fork Rancheria*
P.O. Box 929
North Fork, CA 93643

Dunlap Band of Mono Indians
P.O. Box 344
Dunlap, CA 93621

Picayune Rancheria*
46575 Road 417
Coarsegold, CA 93614

Table Mountain Rancheria*
23736 Sky Harbor Road
P.O. Box 410
Friant, CA 93626

Mono Nation
P.O. Box 800
North Fork, CA 93643

North Fork Mono Tribe
13396 Tollhouse Road
Clovis, CA 93611

Sierra Nevada Native American Coalition
P.O. Box 125
Dunlap, CA 93621

Bishop Tribal Council
50 Tu Su Lane
Bishop, CA 93514

Sierra Mono Museum
33103 Road 288
North Fork, CA 93643

Native Earth Foundation
34329 Shaver Springs Road
Auberry, CA 93602

Michahai Wuksachi
1174 Rockhaven Ct
Salinas, CA 93906

*Federally recognized tribal organization

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 1 AND 2
(FERC Project No. 2175)

EXHIBIT A: DESCRIPTION OF PROJECT

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit A Description of Project

Exhibit A is a description of the project. This exhibit need not include information on project works maintained and operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, or any other department or agency of the United States, except for any project works that are proposed to be altered or modified. If the project includes more than one dam with associated facilities, each dam and the associated component parts must be described together as a discrete development. The description for each development must contain

> (1) The physical composition, dimensions, and general configuration of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, to be included as part of the project;
>
> (2) The normal maximum surface area and normal maximum surface elevation (mean sea level), gross storage capacity and usable storage capacity of any impoundments to be included as part of the project;
>
> (3) The number, type, and rated capacity of any turbines or generators, whether existing or proposed, to be included as part of the project;
>
> (4) The number, length, voltage, and interconnections of any primary transmission lines, whether existing or proposed, to be included as part of the project [see 16 U.S.C. 796(11)];
>
> (5) The specifications of any additional mechanical, electrical, and transmission equipment appurtenant to the project; and
>
> (6) All lands of the United States that are enclosed within the project boundary described under each paragraph (h) of this section (Exhibit G), identified and tabulated by legal subdivisions of a public land survey of the affected area or, in the absence of a public land survey, by the best available legal description. The tabulation must show the total acreage of the lands of the United States within the project boundary.

(1) General Configuration

The Big Creek Powerhouse Nos. 1 and 2 Project is located near the town of Big Creek on the western slope of the Sierra Nevada range, approximately 65 miles northeast of the City of Fresno, California. Part of the town of Big Creek is included within the FERC Project Boundaries, and provides administration, offices, meeting rooms, cooking facilities, a warehouse, a hazardous materials storage facility, a wastewater treatment plant, a garage, a helipad, crew meeting rooms, a tool room, and housing for workers and their families and for guests.

Project facilities, shown in Figure A-1, are located in Fresno County, California and within the Sierra National Forest, which is administered by the United States Department of Agriculture-Forest Service (USDA-FS). The Project is operated as a reservoir-storage type plant with an installed operating capacity of 154.85 MW. Water for Powerhouse No. 1 is taken from Huntington Lake and conveyed to the powerhouse through Tunnel No. 1 and is discharged into the impoundment behind Dam 4, which also receives water from Big Creek and Pitman Creek. Water for Powerhouse No. 2 is taken from the impoundment behind Dam 4 via Tunnel No. 2, which subsequently receives additional inputs from Balsam Creek and Ely Creek. The energy generated by the Project is transmitted to the SCE transmission and distribution system and used for public utility purposes.

Big Creek Powerhouse No. 1

Huntington Lake Dam No. 1

Huntington Lake Dam No. 1 is located within Section 14, T8S, R25E, M.D.B. and M. The dam was originally constructed in 1912-1913 as a concrete gravity structure and was raised in 1917 concurrently with the raising of Dam Nos. 2, 3, and 3A to provide the current normal reservoir level at an elevation of 6,950 feet msl. The Dam No. 1 was extensively modified by supplementing the spillway, placing earth fill against the downstream face and part of the upstream face, and covering a major portion of the upstream face with steel sheathing. The dam is 170 feet high and the crest length is 1,335 feet at an elevation of 6,953.5 feet msl.

There are two spillways located at Dam No. 1. The original was constructed as a series of seven siphon sections, each 10 feet wide, that now operate as overflow weirs since the siphons were opened to air at their high points. The crest of the overflow weirs is at an elevation of 6,950 feet msl. The second spillway consists of a 110-foot long concrete ogee weir section with the crest elevation at 6,945 feet msl. This section is provided with 15 manually-operated vertical lift slide gates, each 5 feet high by 12 feet wide. The tops of the gates in the closed (up) position are also at an elevation of 6,950 feet msl. The rated capacity of the gated spillway at water surface elevation of 6,950 feet msl is 7,000 cfs. The rated capacity of the combined spillways at water surface elevation 6,953 feet msl is 16,500 cfs.

Dam No. 1 has a 9-foot diameter steel outlet pipe with the invert at an elevation of 6,820 feet msl leading to Tunnel No. 1 and controlled by a slide gate operated from a tower in the lake near the dam. The dam is also provided with three 42-inch pipes passing through the base at an

Placeholder for Figure A-1
Project Facilities Big Creek 1 and 2

<u>Non-Internet Public Information</u>

This Figure has been removed in accordance with the Commission regulations at 18 CFR Section 388.112.

This Figure is considered Non-Internet Public information and should not be posted on the Internet. This information is provided in Volume 3 of the Application for New License and is identified as "Non-Internet Public" information. This information may be accessed from the FERC's Public Reference Room, but is not expected to be posted on the Commission's electronic library, except as an indexed item.

elevation of 6,808 feet msl, and a 72-inch pipe through the right abutment at an elevation of 6,921 feet msl. All four outlets are equipped with slide gates at both the upstream and downstream ends.

Huntington Lake Dam No. 2

Huntington Lake Dam No. 2 is located within Section 15 and Section 22, T8S, R25E, M.D.B. and M. The dam was originally constructed in 1913 as a concrete gravity dam and was raised in 1917 concurrently with the raising of Dam Nos. 1 and 3 to provide the current normal reservoir surface elevation of 6,950 feet msl. The dam was extensively modified by placing earth fill against both the upstream and downstream faces of the concrete structure to improve stability and protect against freezing, and to cover the upstream face near the outlet tunnel with sheet steel. The dam is 120 feet high, and the crest length is 1,862 feet at an elevation of 6,953.5 feet msl.

No spillway has been provided for Dam No. 2. The spill from the lake is discharged over the spillways at Dam No. 1, as described above.

Dam No. 2 outlet works consist of a 10-foot diameter steel pipe with an invert at an elevation of 6,885 feet msl connecting to the Huntington–Shaver Tunnel (also known as Tunnel No.7), a part of the Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67). A 10-foot slide gate, protected by a trash rack, controls the inlet and is a guard for a 9-foot duplex valve located in a valve housing buried under the downstream fill.

Huntington Lake Dam No. 3

Huntington Lake Dam No. 3 is located within Section 22, T8S, R25E, M.D.B. and M. The dam was originally constructed in 1913 as a concrete gravity dam. It was raised in 1917 concurrently with the raising of Dam Nos. 1 and 2, to provide the current normal reservoir surface elevation of 6,950 feet msl. The dam was extensively modified by placing earth fill against both the upstream and downstream dam faces to increase stability and protect from freezing. The dam is 165 feet high, and the crest length is 640 feet at an elevation of 6,953.5 feet msl. No spillway has been provided for Dam No. 3. The spill from the lake is discharged over the spillways at Dam No. 1, as described above. There are no outlet works in the dam.

Huntington Lake Dam No. 3A

Huntington Lake Dam No. 3A is located within Section 22, T8S, R25E, M.D.B. and M. The dam was originally constructed in 1917 as a concrete gravity structure when Dam Nos. 1, 2, and 3 were raised, to provide a normal reservoir surface level at an elevation of 6,950 feet msl. The dam was extensively modified by placing earth fill against both faces of the dam in 1936-1938 and additional backfill was added in 1966 to completely cover the upstream face to protect against freezing. The dam is 22.5 feet high, and the crest length is 263 feet at an elevation of 6,953.5 feet msl. No spillway has been provided for Dam No. 3A. The spill from the lake is discharged over the spillways at Dam No. 1, as described above. There are no outlet works in the dam.

Tunnel No. 1

The Powerhouse No. 1 flowline consists of Tunnel No. 1, a 12-foot diameter, 3,946-foot long, generally unlined tunnel through granite. The downstream end of Tunnel No. 1 is lined with a 108-inch diameter, 409-foot long, riveted steel pipe which branches into two riveted steel pipes as it emerges from the tunnel. The first branch, 84 inches in diameter and 6,459 feet long, connects to Units No. 1, 2, and 3 penstocks. Flow through this pipe is controlled by an 84-inch butterfly valve located at the downstream end of the pipe and operated either locally from Powerhouse No. 1 or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). The second branch, 60 inches in diameter and 6,478 feet long, connects to the Unit No. 4 penstock. Flow through this pipe is controlled by a 54-inch valve, located at the downstream end of the pipe and operated either locally from Powerhouse No. 1, or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). Tunnel No. 1 is designed to convey approximately 700 cfs under optimum conditions.

Penstocks

Four penstocks are associated with Powerhouse No. 1. These penstocks consist of the following:

- The penstocks associated with Units No. 1 and 2 are 4,311 feet long and consist of 44-inch diameter welded steel pipe that reduces to 36 inches in diameter before branching into two 26-inch lines outside the powerhouse. Each of the branches further reduces to 24 inches in diameter before connecting to either side of the turbines on Unit Nos. 1 and 2.

- The penstock associated with Unit No. 3 is 4,360 feet long and consists of a 42-inch diameter welded steel pipe which reduces to 36 inches in diameter before branching into two 26-inch lines outside the powerhouse. Each of the branches further reduces to 24 inches in diameter before connecting to either side of the turbine on Unit No. 3.

- The penstock associated with Unit No. 4 is 4,301 feet long and consists of a 54-inch diameter welded steel pipe, which reduces to 36 inches in diameter before branching into two 34-inch lines outside the powerhouse. Each of the branches further reduces to 24 inches in diameter before connecting to either side of the turbine on Unit No. 4.

The upstream end of each penstock is equipped with an electric motor-operated gate valve controlled either locally from Powerhouse No. 1 or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). An air vent is situated immediately downstream of the gate valve in each penstock. The air vent consists of a vertical 36-inch diameter steel pipe that is approximately 28 feet high with a top elevation of 6,990 feet msl. A sonic flow device is used to sense excess flow in the penstock.

Big Creek Powerhouse No. 1

The basement of the powerhouse consists of storage for tools and parts, oil storage tanks, piping, sumps, a sewer septic tank and access to lower portions of the turbines. The ground floor of the powerhouse consists of a machine shop equipped with a 1.5-ton rail crane, drill presses, lathes, weld table, shaper, power hacksaw, and miscellaneous small tools used to maintain and repair the powerhouse equipment. The second floor of the powerhouse consists of a control room, lunch room and office space. A third floor provides space for storage of large mechanical parts. The fourth floor contains Generator Circuit Breakers and the fifth floor is used for storage.

Tailrace

The Powerhouse No. 1 tailrace is impounded by Dam 4, as described above. The Dam 4 impoundment collects water discharged from the powerhouse turbines and water not previously diverted from Big Creek below Huntington Lake and Pitman Creek. The Dam 4 impoundment has a capacity of 60 acre-feet, and serves as the regulating forebay for Powerhouse No. 2. The intake structure for Tunnel No. 2, which leads to Powerhouse No. 2, is located a short distance upstream of the left abutment of Dam 4.

Adits

There is one adit (Incline Adit) connected to Tunnel No. 1. The adit was part of the construction of the tunnel and is occasionally used for inspection or maintenance of the tunnel.

Big Creek Powerhouse No. 1 Controls

Controls include electrically operated alarm circuits to warn of abnormal operation conditions; automatic-trip oil circuit breakers; automatic load, speed, and voltage control; meters; relays; and remote control equipment. Telephone circuits of the company's integrated communication system are connected to the powerhouse control room. A system has been installed which permits computer control locally at Powerhouse No. 1 and from non-Project Big Creek Powerhouse No. 3 (FERC Project No. 120) via a Local Controller (LC) to monitor and operate the units. The LC can automatically monitor and shut down the units, but operator intervention is required to put the units online. The computer system is equipped with a printer, keyboard, and monitor to allow the operator to perform local plant control and monitoring. The LC also allows plant technicians to modify, troubleshoot, and diagnose the control system and plant parameters. The medium of control transmission is microwave radio frequency.

Big Creek Powerhouse No. 2

Big Creek Dam No. 4

Big Creek Dam No. 4 consists of a 75-foot high constant-radius concrete arch dam, with a crest length of 287 feet at an elevation of 4,805 feet msl. A steel walkway, which spans the full length, is above the dam at an elevation of 4,814 feet msl. The dam has a spillway consisting of 27 ungated bays, separated by piers with a total length of 187 feet. The spillway is provided with flashboards. The crest without the flashboards is at an elevation of 4,805 feet msl. The reservoir net storage capacity with the flashboards in place, at an elevation of 4,810 feet msl, is 59.7 acre-feet. The rated discharge capacity at the spillway is 7,000 cfs.

The dam outlet works are located a short distance upstream from the left abutment, forming the entrance to Tunnel No. 2, which leads to Powerhouse No. 2. The tunnel is 12 feet in diameter with the invert at elevation 4,788.5 feet. The tunnel does not have an intake gate and stoplogs must be installed to dewater the tunnel.

Balsam Creek Diversion

The Balsam Creek Diversion, located across Balsam Creek approximately 2 miles southwest of Big Creek, consists of a concrete diversion that is 9 feet high with a crest length of 72 feet. Diverted water is conveyed through approximately 400 feet of 12-inch diameter steel pipe to Tunnel No. 2 where it enters through Adit No. 3. Flow through the conduit is controlled by a gate valve located upstream of the diversion structure.

Ely Creek Diversion

The Ely Creek Diversion, located across Ely Creek approximately 3 miles southwest of Big Creek, consists of a concrete diversion that is 7-feet high with a crest length of 44 feet. Diverted water is conveyed through approximately 300 feet of 12-inch diameter steel pipe to Tunnel No. 2 where it enters through Adit No. 6. Flow through the conduit is controlled by a gate valve located upstream of the diversion structure.

Adit 8 Diversion

The Adit 8 Diversion, located on Adit 8 Creek about 3.5 miles southwest of Big Creek, consists of a concrete diversion approximately 30 feet high with a crest length of approximately 44 feet. When used, water is diverted through a vertical borehole that intersects Tunnel No. 2 at Adit 8.

The Adit 8 Diversion was built to divert Tunnel No. 5 water (from Shaver Lake) into Tunnel No. 2 (to Powerhouse No. 2). A bulkhead was poured in Tunnel No. 5 with a pipe leading downhill to a valve and an energy dissipation structure just above the Adit 8 diversion. The bulkhead, piping, valve, and energy dissipation structure are known as the Shoo Fly.

Tunnel No. 2

The Powerhouse No. 2 flowline consists of Tunnel No. 2, a 12-foot diameter, 21,759-foot long, generally unlined bore through granite which intersects the base of a surge tank at its downstream end. The surge tank is a mostly underground, concrete-lined tank, 30 feet in diameter and 115 feet high. A 108-inch diameter, 255-foot long, riveted steel pipe exits from the base of the surge tank and divides unsymmetrically into four penstocks. Flow through this pipe is controlled by an electrically operated, 108-inch slide gate on the inside wall of the surge tank. The gate can be operated either locally from Powerhouse No. 2 or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120).

Penstocks

Four penstocks are associated with Powerhouse No. 2. These penstocks consist of 44-inch diameter pipes which reduce to 36 inches in diameter before bifurcating to 24-inch legs just outside the powerhouse. Each of the eight legs connects to one side of four horizontal-shaft Pelton turbines in the powerhouse. The penstocks are further described as follows:

- The Unit No. 3 penstock is 4,395 feet long and is constructed of riveted and welded steel pipe.

- The Unit No. 4 penstock is 4,387 feet long and is constructed of riveted and welded steel pipe.
- The Unit No. 5 penstock is 4,640 feet long and is constructed of riveted and forged seamless steel pipe.
- The Unit No. 6 penstock is 4,635 feet long and is constructed of forged seamless steel pipe.

Each penstock is controlled at its upstream end by an electric motor-operated, 42-inch gate valve operated either locally from Powerhouse No. 2 or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120). An air vent is situated approximately 24 feet downstream from the gate valve in each penstock. The air vent consists of a vertical 44-inch diameter steel pipe that is approximately 107 feet high. A sonic flow device is used to sense excess flow in the penstock.

Tailrace

The tailrace for Big Creek Powerhouse No. 2 is created by Dam 5, described in Exhibit A for the Big Creek Nos. 2A, 8 and Eastwood Project (FERC Project No. 67). The Dam 5 impoundment collects water that has passed through the turbines of both Big Creek Powerhouse No. 2 and adjacent non-Project Big Creek Powerhouse No. 2A (FERC Project No. 67) and from Big Creek and its tributaries situated upstream of Dam 5. The Dam 5 impoundment has a capacity of 49 acre-feet, and serves as the regulating forebay for non-Project Big Creek Powerhouse No. 8 (FERC Project No. 67).

Adits

There are nine adits connected to Tunnel No. 2. The adits were part of the construction of the tunnel and are occasionally used for inspection or maintenance of the tunnel.

Big Creek Powerhouse No. 2

The basement of the powerhouse consists of storage for tools and parts, oil storage tanks, piping, sumps and a sewer septic tank. The ground floor of the powerhouse houses an office and a machine shop equipped with drill presses, weld table, power hacksaw, and other miscellaneous small tools used to maintain and repair the powerhouse equipment. The second floor of the powerhouse consists of a control room and lunch room. A third floor provides space for storage of large mechanical parts. The fourth floor contains Generator Circuit Breakers and the fifth floor is used for storage. Powerhouse No. 2 shares its control room, maintenance and personnel facilities with non-Project Powerhouse No. 2A (FERC Project No. 67).

Big Creek Powerhouse No. 2 Controls

Controls include electrically operated alarm circuits to warn of abnormal operation conditions; automatic trip oil circuit breakers; automatic load, speed, and voltage control; meters; relays; and remote control equipment. Telephone circuits of the company's integrated communication system are connected to the powerhouse control room. A computer control system has been installed which permits computer control locally and from non-Project Big Creek Powerhouse No. 3 via a Local Controller (LC) to monitor and operate the units. The LC can automatically monitor and shut down the units, but operator intervention is required to put the units online. The computer system is equipped with a printer, keyboard, and monitor to allow the operator to perform local plant control and monitoring. The LC also allows plant technicians to modify, troubleshoot, and diagnose the control system and plant parameters.

(2) Storage Capacity

Huntington Lake has a surface area of 1,435 acres and a gross storage capacity and usable capacity of 89,166 acre-feet at the spillway elevation of 6,950 feet msl. Huntington Lake provides water to both FERC Project No. 2175 through Powerhouse No. 1 and FERC Project No. 67 through the Huntington-Pitman Siphon (Tunnel 7). Because the two outlets are located at different elevations, at the spillway elevation of 6,950 feet msl, Huntington Lake has a usable storage capacity of 89,166 acre-feet for FERC Project No. 2175 and a usable capacity of 69,726 acre-feet for FERC Project No. 67.

The Powerhouse No. 2 Forebay formed by Dam 4 has a gross storage capacity of 60 acre-feet and a usable storage capacity of 56 acre-feet with the flashboards in place, at a water surface elevation of 4,810 feet msl.

(3) Turbines and Generators

Big Creek Powerhouse No. 1

The powerhouse contains four Pelton-type horizontal shaft, single jet, double overhung, hydraulic impulse turbines. The total powerhouse rating is 128,210 HP. The individual ratings for each turbine are as follows:

- The Unit 1 turbine is rated at 29,025 HP at a design head of 1,885 feet and operating at 450 RPM;
- The Unit 2 turbine is rated at 28,060 HP at a design head of 1,885 feet and operating at 450 RPM;
- The Unit 3 turbine is rated at 29,025 HP at a design head of 1,885 feet and operating at 450 RPM; and

- The Unit 4 turbine is rated at 42,100 HP at a design head of 1,960 feet and operating at 360 RPM.

The four generators associated with the Project consist of horizontal shaft, partially enclosed units. The generator specifications are as follows:

- The Unit 1 generator consists of a General Electric unit that is rated at 19,800 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 2 generator consists of a General Electric unit that is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 3 generator consists of a General Electric unit that is rated at 21,600 kW, 0.9 power factor, 13.8 kV, three-phase, 60 Hz.
- The Unit 4 generator consists of a Westinghouse unit that is rated at 31,200 kW, 1.0 power factor, 13.2 kV, three-phase, 60 Hz.

Cooling is provided by air drawn from within the powerhouse with the aid of fans on the rotors. The main exciter generator and permanent magnet generator (PMG) are directly connected to the end of each generator shaft. Automatic voltage regulation is performed by solid-state type regulators.

Each main generator is protected by two 15 kV, 3,000 amp, oil circuit breakers connected in a breaker-and-a-half arrangement between Units 1 and 2 and between Units 3 and 4. Disconnect switches are provided at each breaker position for isolation.

Big Creek Powerhouse No. 2

The powerhouse contains four Pelton-type horizontal shaft, single jet, double overhung, hydraulic impulse turbines. The total powerhouse rating is 100,990 HP. The individual ratings for each turbine are as follows:

- The Unit 3 turbine is rated at 27,270 HP at a design head of 1,610 feet and operates at 450 RPM;
- The Unit 4 turbine is rated at 27,270 HP at a design head of 1,610 feet and operates at 450 RPM;
- The Unit 5 turbine is rated at 21,450 HP at a design head of 1,645 feet and operates at 450 RPM; and
- The Unit 6 turbine is rated at 25,000 HP at a design head of 1,660 feet and operates at 450 RPM.

The four generators associated with the Project consist of horizontal shaft, partially enclosed Westinghouse units. The generator specifications are as follows:

- The Unit 3 generator is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 4 generator is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 5 generator is rated at 17,500 kW, 1.0 power factor, 6.6 kV, three-phase, 60 Hz.
- The Unit 6 generator is rated at 17,500 kW, 1.0 power factor, 6.6 kV, three-phase, 60 Hz.

Cooling is provided by air drawn from within the powerhouse with the aid of fans on the rotors. The main exciter generator and PMG are directly connected to the end of each generator shaft on units 5 and 6. On unit 3 the main exciter generator is connected directly to the generator shaft, but is not connected electrically and a static exciter is used. On unit 4 the main exciter generator was removed and a stub shaft connects the PMG directly to the generator shaft. Automatic voltage regulation is performed by solid-state type regulators. A 200 kW Westinghouse 250 volt direct current generator, connected to a 350 hp, 750 RPM impulse water turbine is provided for a spare exciter and a source of auxiliary direct current.

Each main generator is protected by two 15 kV, 3,000 amp, oil circuit breakers connected in a breaker-and-a-half arrangement between Units 3 and 4 and between Units 5 and 6. Disconnect switches are provided at each breaker position for isolation.

(4) Primary Transmission Lines

There are no transmission lines associated with this Project.

(5) Mechanical, Electrical and Transmission Equipment

Big Creek Powerhouse No. 1

Oil Storage and Handling System

There are oil storage and transfer facilities for governor and bearing lubricating oil. Separate clean oil and used oil tanks are provided with an in-line centrifuge to purify lubricating and governor oil, as needed.

Cooling Water System

Cooling water for bearing oil coolers and pressure regulator control water is obtained from the Unit No. 1 or Unit No. 2 penstocks through a 900 psig header and returned to the tailrace after once-through use as a coolant. When the 900 psig header is out of service, water is supplied to the cistern from the wheel pits of Unit No. 1 and No. 2 generators and then pumped into the system.

Valves

The downstream end of Tunnel No. 1 is lined with a 108-inch diameter riveted steel pipe which branches into two riveted steel pipes as it emerges from the tunnel. The first branch is 84-inches in diameter and connects to the Unit Nos. 1, 2, and 3 penstocks. Flow through this pipe is controlled by an 84-inch butterfly valve located at the downstream end of the pipe and operated either locally from Powerhouse No. 1 or remotely from the non-project Big Creek No. 3 Control Center (FERC Project No. 120). The second branch is 60-inches in diameter and connects to the Unit No. 4 penstock. Flow through this pipe is controlled by a 54-inch gate valve located at the downstream end of the pipe. The gate valve is operated either locally from Powerhouse No. 1, or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120).

The upstream end of each penstock is equipped with an electric motor-operated 42-inch gate valve that can be controlled either locally from Powerhouse No. 2 or remotely from the non-Project Big Creek No. 3 Control Center (FERC Project No. 120).

The turbine shut-off valves for Units 1, 2, and 3 are 24-inch, hydraulically operated gate valves. The turbine shut-off valves for Unit 4 are 30-inch, hydraulically-operated gate valves. Valve operation for each turbine is accomplished by supplying penstock pressure water to the operating cylinder by means of an electrically or manually operated control water mechanism.

The powerhouse turbine relief valves consist of oil dashpot cylinder-type valves with a direct link to the governor operating mechanism. The valves are situated on each side of the units and are directly connected to the respective turbine tail races. The valve operates normally as a penstock relief valve. Units 1, 2, and 3 can be adjusted to operate as synchronous by-pass valves in conjunction with turbine operation.

Governors

Normal turbine operating speed control is maintained by a Woodward governor system on each unit. The governors are controlled by either manual operation or automatic devices.

The governor oil system consists of two identical governor oil pumps, motors, main pressure tanks and sumps. The two main pressure tanks and the two sumps are normally operated in parallel using either of the governor oil pumps.

In addition to the main pressure tanks, there are two cushion tanks to provide extra capacity for the governor oil system. An air compressor is provided to maintain the air cushion in the pressure tanks.

Gages

The following gages are associated with this Powerhouse:

USGS No.	SCE No.	Station Name
11236000	149	Huntington Lake
11237000	104	Big Creek below Huntington Lake (Dam 1)
11238100	159	Big Creek PH No. 1

Generators

The four generators associated with the Project consist of horizontal shaft, partially enclosed units. The generator specifications are as follows:

- The Unit 1 generator consists of a General Electric unit that is rated at 19,800 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 2 generator consists of a General Electric unit that is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 3 generator consists of a General Electric unit that is rated at 21,600 kW, 0.9 power factor, 13.8 kV, three-phase, 60 Hz.
- The Unit 4 generator consists of a Westinghouse unit that is rated at 31,200 kW, 1.0 power factor, 13.2 kV, three-phase, 60 Hz.

Cooling is provided by air drawn from within the powerhouse with the aid of fans on the rotors. The main exciter generator and PMG are directly connected to the end of each generator shaft. Automatic voltage regulation is performed by solid-state type regulators.

Each main generator is protected by one 15 kV, 3,000 amp, vacuum breaker. Disconnect switches are provided at each breaker position for isolation.

Transformers

The only transformers associated with the Project are associated with the Powerhouse service power and lighting.

Power Distribution Equipment

Powerhouse service power is obtained from the station buses through four single-phase, 150 kVA, 7.2 kV-240/120 volt transformers connected to form three-phase and single-phase banks. A three-phase, 3,000 kVA, 13.2-7.2 kV auto-transformer is used between the 7.2 and 13.2 kV buses. Powerhouse DC control power is provided by a 60-cell, 410 ampere-hour, 125-volt bank of lead-acid storage batteries charged with a solid state battery charger.

Heating, Ventilating, and Air Conditioning System

The powerhouse is ventilated by natural draft and fans. Air cooling and heating for the control room is provided by a centralized unit.

Compressed Air System

The powerhouse contains two electric motor-driven stationary air compressors complete with receivers and piping for general station use. The main station air compressor supplies air at 90-110 psig and the auxiliary compressor at 60-90 psig.

An additional air compressor complete with receivers and piping supplies air cushions in the governor oil pressure tanks.

Fire Protection System

Portable 150-pound Halon units are located on the generator floor for Unit fire protection. Portable extinguishers, fire hoses, reels, and hydrants are provided in strategic locations within the powerhouse.

Sanitary Disposal System

Sanitary facilities are provided in two locations within the powerhouse. One small restroom facility is located in the control room and a large crew restroom area is centrally located on the first floor. The effluent is processed in the waste water treatment plant within the Big Creek 1 Camp location. The normal source of the plant's service water is Penstock water.

Lighting

Normal powerhouse lighting service is supplied from the station buses through one single-phase, 150 kVA, 7.2 kV-240/120 volt transformer. A three-phase, 3,000 kVA, 13.2-7.2 kV auto-transformer is used between the 7.2 and 13.2 kV buses. Emergency DC lighting is provided from the powerhouse battery system to facilitate safe operation in the event of a lighting system failure or system outage.

Station Crane

The powerhouse is equipped with a 100-ton traveling overhead crane with a 5-ton auxiliary hook which provides hoisting facilities for all major equipment. There are two monorail 5-ton chain hoists provided for the powerhouse shops. There is also a monorail 5-ton tower hoist provided for the powerhouse fifth floor storage area.

Switching

The non-Project switchyard is located approximately 450 feet west of the powerhouse. The Project switchgear consists of four remotely-operated circuit breakers. Units 1 and 2 circuit breakers are 3000 ampere, 7 kV each and Units 3 and 4 circuit breakers are 3000 ampere, 13 kV each.

Big Creek Powerhouse No. 2

Oil Storage and Handling System

There are oil storage and transfer facilities for governor and bearing lubricating oil. Separate clean oil and used oil tanks are provided with an in-line centrifuge to purify lubricating and governor oil as needed. A portable oil filtering machine is also available.

Cooling Water System

Cooling water for the bearing oil cooler is obtained from the station cistern by means of cooling water pumps and returned to the tailrace after once-through use as a coolant. Water is supplied to the cistern from the wheel pits of three units at Powerhouse No. 2 and from one unit at non-project Powerhouse No. 2A (FERC Project No. 67). Non-Project Dam 5 (part of Project 67 and just downstream of Powerhouse No. 2) and penstocks 3 and 4 are alternate sources of cooling water.

Valves

Flow through the 108-inch diameter, 255-foot long, riveted steel pipe that exits from the base of the surge tank in Tunnel No. 2 is controlled by an electrical motor-operated, 108-inch slide gate on the inside wall of the surge tank. The gate is operated either locally from Powerhouse No. 2 or remotely from the Big Creek No. 3 Control Center (FERC Project No. 120).

The upstream end of each penstock is equipped with an electric motor-operated 42-inch gate valve, controlled either locally from Powerhouse No. 2 or remotely from the Big Creek No. 3 Control Center (FERC Project No. 120).

The turbine shut-off valves for Units 3 and 4 consist of 24-inch, hydraulically-operated gate valves. Valve operation is accomplished by supplying penstock pressure water to the operating cylinder by means of a manually-operated control water mechanism.

The turbine shut-off valves for Units 5 and 6 consist of 24-inch, hydraulically-operated gate valves. Valve operation is accomplished by supplying penstock water pressure to the operating cylinder by means of a manually-operated handwheel which places the five-way control valve into position to pressurize the operating cylinder for the desired mode of operation.

The powerhouse turbine relief valves consist of oil dashpot cylinder-type valves with a direct link to the governor operating mechanism. The valves are situated on each side of the units and are directly connected to the respective turbine tail races. The valve operates normally as a penstock relief valve. However, Units 3 and 4 can be adjusted to operate as synchronous by-pass valves in conjunction with turbine operation.

Governors

Normal turbine operating speed control is maintained by a Woodward governor system on each unit. The governors are controlled either manually or automatically.

The governor oil system, shared in common with Powerhouse No. 2A, consists of two identical governor oil pumps, motors, main pressure tanks, sumps and one emergency back-up pump driven by a water turbine. Normally the two main pressure tanks and the two sumps are operated in parallel using either of the motor-driven governor oil pumps.

In addition to the main pressure tanks, five cushion tanks provide extra capacity for the governor oil system. Two air compressors are provided to maintain the air cushion in the pressure tanks.

Gages

The following gages are associated with this Powerhouse:

USGS No.	**SCE No.**	**Station Name**
N/A	101	Balsam Creek at Diversion Dam
N/A	112	Ely Creek at Diversion Dam
11238380	160	Big Creek Powerhouse No. 2

Generators

The four generators associated with the Project consist of horizontal shaft, partially enclosed Westinghouse units. The generator specifications are as follows:

- The Unit 3 generator is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 4 generator is rated at 15,750 kW, 0.9 power factor, 8.0 kV, three-phase, 60 Hz.
- The Unit 5 generator is rated at 17,500 kW, 1.0 power factor, 6.6 kV, three-phase, 60 Hz.
- The Unit 6 generator is rated at 17,500 kW, 1.0 power factor, 6.6 kV, three-phase, 60 Hz.

Cooling is provided by air drawn from within the powerhouse with the aid of fans and the rotors. The main exciter generator and PMG are directly connected to the end of each generator shaft on units 5 and 6. On unit 3 the main exciter generator is connected directly to the generator shaft, but is not connected electrically and a static exciter is used. On unit 4 the main exciter generator was removed and a stub shaft connects the PMG directly to the generator shaft. Automatic voltage regulation is performed by solid-state type regulators. A 200 kW Westinghouse 250 volt direct current generator, connected to a 350 hp, 750 rpm impulse water turbine is provided for a spare exciter and source of auxiliary direct current.

Each main generator is protected by one 15 kV, 3,000 amp, vacuum breaker. Disconnect switches are provided at each breaker position for isolation.

Transformers

The only transformers associated with the Project are associated with the Powerhouse service power and lighting.

Power Distribution Equipment

Powerhouse service power is supplied from the station buses through two three-phase transformer banks consisting of six Westinghouse single-phase 150 kVA, 7.2 kV-230/115 volt transformers. The banks are used alternately to supply power to the station. Powerhouse dc control power is supplied by a 60-cell, 440 Ampere-hour, 125-Volt, lead acid-type storage battery bank charged by a solid state battery charger.

Heating, Ventilating, and Air Conditioning System

The powerhouse is ventilated by natural draft. Air cooling and heating for the control room is provided by a centralized unit.

Compressed Air System

A non-Project common electric motor-driven stationary air compressor complete with receiver and piping for general station use is located in the adjacent Big Creek No. 2A powerhouse.

Fire Protection System

Portable 150-pound Halon units are located on the generator floor for generator unit fire protection. Portable extinguishers, fire hoses, reels, and hydrants are provided in strategic locations within the powerhouse.

Sanitary Disposal System

Sanitary facilities are provided in two locations within the powerhouse. One small restroom facility is located in the control room and a large crew restroom area is centrally located on the first floor. The normal source of the plant's service water is from the penstocks. Effluent from the restrooms, floor drains, and sinks is processed in an on-site septic tank located and pumped to a leach field.

Lighting

Normal powerhouse lighting service is supplied by two single-phase 150 kVA, 7.2 kV, 230/115 Volt transformers working alternately with each other. Emergency DC lighting is provided from the powerhouse battery system to facilitate safe operation in the event of a lighting system failure or system outage.

Station Crane

The powerhouse is equipped with a 85-ton traveling overhead crane with a 5-ton auxiliary hook which provides hoisting facilities for all major equipment.

Switching

A non-Project switchyard is located approximately 300 feet from the powerhouse. The switchyard consists of an Upper Bus, a Lower Bus, and four double-breaker, double-bus positions. The positions are electrical double-breaker, double-bus positions, but their physical layout is unique. They are folded 180 degrees at the midpoint so that the two halves are adjacent. The positions are built on steep terrain with each component at a different elevation. The elevation change from the lowest part of the switchyard to the highest exceeds 110 feet. The switchyard is bermed and has an oil-water separator to capture any discharged oil, in case of equipment failure in the switchyard, before it reaches a waterway.

(6) Lands of the United States within Project Boundaries

Lands of the United States within the Project boundaries, including legal subdivisions and acreages, are listed in Table A-1.

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 1 and 2 Project. (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 24 East, MDM	
Section 25	
SE1/4 SW1/4	3.19
SW1/4 SW1/4	31.57
NW1/4 SW1/4	0.22
Section 26	
NE1/4 SE1/4	0.02
SE1/4 SE1/4	29.90
SW1/4 SE1/4	7.25
Section 35	
NE1/4 NE1/4	3.09
SE1/4 NE1/4	1.53
Section 36	
NE1/4 SW1/4	8.03
NW1/4 SW1/4	3.24
NE1/4 SE1/4	1.52
NW1/4 SE1/4	3.18
SE1/4 NE1/4	4.08
SW1/4 NE1/4	0.11
SW1/4 SE1/4	3.53
SE1/4 SW1/4	3.59
NE1/4 NW1/4	7.08
SE1/4 NW1/4	12.87
SW1/4 NW1/4	9.32
NW1/4 NW1/4	12.90
Township 8 South, Range 25 East, MDM	
Section 11	
NE1/4 SE1/4	1.36
SE1/4 SE1/4	29.53
SW1/4 SE1/4	2.50
Section 12	
NW1/4 SW1/4	16.26
SW1/4 SW1/4	33.94
SE1/4 NE1/4	9.45
SW1/4 NE1/4	1.32
NE1/4 SE1/4	34.06
SE1/4 SE1/4	30.67
SW1/4 SE1/4	33.54
NW1/4 SE1/4	32.92
NE1/4 SW1/4	29.94
SE1/4 SW1/4	34.02
SE1/4 NW1/4	2.61
SW1/4 NW1/4	0.33

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 1 and 2 Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 25 East, MDM (continued)	
Section 13	
NE1/4 NE1/4	0.48
NW1/4 NE1/4	1.21
NE1/4 NW1/4	3.22
NW1/4 NW1/4	9.75
Section 14	
SE1/4 NE1/4	2.39
SW1/4 NE1/4	19.38
NW1/4 NE1/4	34.46
NE1/4 SW1/4	11.88
SW1/4 SW1/4	1.64
NW1/4 SW1/4	19.60
NE1/4 NW1/4	12.69
SW1/4 NW1/4	33.94
NW1/4 NW1/4	0.01
Section 15	
SE1/4 NE1/4	4.82
SW1/4 NE1/4	21.85
NE1/4 SE1/4	37.50
SE1/4 SE1/4	19.44
SW1/4 SE1/4	40.00
SE1/4 SW1/4	40.00
SW1/4 SW1/4	28.87
NW1/4 SW1/4	14.56
SE1/4 NW1/4	23.13
SW1/4 NW1/4	6.77
Section 16	
SE1/4 NE1/4	2.94
NE1/4 SE1/4	0.15
SE1/4 SE1/4	0.01
Section 21	
NE1/4 NE1/4	3.42
NE1/4 SE1/4	2.22
SE1/4 SE1/4	11.74
Section 22	
NE1/4 NE1/4	8.40
NW1/4 NE1/4	31.03
SW1/4 NE1/4	0.66
NE1/4 SW1/4	0.03
NW1/4 SW1/4	14.45
NE1/4 NW1/4	7.94
SE1/4 NW1/4	8.80

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 1 and 2 Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 25 East, MDM (continued)	
Section 22 (continued)	
SW1/4 NW1/4	8.72
NW1/4 NW1/4	32.84
SW1/4 SW1/4	11.35
Section 23	
SE1/4 NW1/4	0.67
SW1/4 NW1/4	3.48
NW1/4 NW1/4	1.57
Section 27	
SW1/4 NW1/4	0.62
NW1/4 NW1/4	0.04
SW1/4 SW1/4	1.13
NW1/4 SW1/4	1.14
Section 28	
NE1/4 SW1/4	19.03
NW1/4 SE1/4	39.85
SE1/4 SE1/4	2.19
NE1/4 SE1/4	23.93
SW1/4 SW1/4	8.01
SE1/4 SW1/4	19.71
SW1/4 SE1/4	5.43
NE1/4 NE1/4	10.06
NW1/4 NE1/4	1.73
SE1/4 NE1/4	12.13
SW1/4 NE1/4	16.21
SE1/4 NW1/4	0.92
Section 31	
NE1/4 SE1/4	0.39
SW1/4 SE1/4	6.73
NE1/4 SW1/4	5.59
SE1/4 NE1/4	3.77
SW1/4 NE1/4	0.63
SE1/4 SE1/4	3.15
SW1/4 SE1/4	3.61
SE1/4 SW1/4	0.92
SE1/4 NW1/4	7.08
SW1/4 NW1/4	2.62
Section 32	
NE1/4 SE1/4	2.70
NW1/4 SE1/4	1.55
SE1/4 SE1/4	0.94
SW1/4 SE1/4	2.93
SE1/4 SW1/4	0.21

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 1 and 2 Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
SW1/4 SW1/4	3.10
Township 8 South, Range 25 East, MDM (continued)	
Section 32 (continued)	
NE1/4 SW1/4	3.53
NW1/4 SW1/4	1.83
Section 33	
SE1/4 NW1/4	3.86
NE1/4 NW1/4	1.24
SW1/4 NW1/4	0.60
NW1/4 NE1/4	2.64
NE1/4 SW1/4	0.03
NW1/4 SW1/4	3.91
Section 34	
NW1/4 NW1/4	0.51
Township 9 South, Range 25 East, MDM	
Section 6	
NE1/4 NE1/4	0.10
NW1/4 NE1/4	4.12
NE1/4 NW1/4	3.63
NW1/4 NW1/4	1.82
Township 8 South, Range 26 East, MDM	
Section 5	
NE1/4 SW1/4	1.81
SE1/4 SW1/4	4.30
SW1/4 SW1/4	9.73
NW1/4 SE1/4	3.82
Section 7	
NE1/4 NE1/4	31.85
SE1/4 NE1/4	40.42
SW1/4 NE1/4	40.27
NW1/4 NE1/4	25.12
NE1/4 SE1/4	19.34
SE1/4 SE1/4	24.38
SW1/4 SE1/4	34.05
NW1/4 SE1/4	40.16
NE1/4 SW1/4	40.49
SE1/4 SW1/4	40.19
SW1/4 SW1/4	38.14
NW1/4 SW1/4	40.42
NE1/4 NW1/4	24.57
SE1/4 NW1/4	40.31
SW1/4 NW1/4	26.29
NW1/4 NW1/4	0.16

Table A-1. Lands of the United States Within the Boundaries of the Big Creek Nos. 1 and 2 Project (continued). (All the lands are under the jurisdiction of the U.S. Forest Service, Sierra National Forest.)

Location	Acres
Township 8 South, Range 26 East, MDM (continued)	
Section 8	
NW1/4 NW1/4	32.58
SW1/4 NW1/4	26.11
NW1/4 SW1/4	0.03
SW1/4 SW1/4	13.72
Section 17	
NW1/4 NW1/4	16.00
Section 18	
NE1/4 NE1/4	14.89
SW1/4 NE1/4	0.44
NW1/4 NE1/4	19.38
NE1/4 NW1/4	14.82
NW1/4 NW1/4	1.62
TOTAL FEDERAL LAND ACREAGE	**1,877.96**

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK Nos. 1 AND 2
(FERC Project No. 2175)

EXHIBIT B: STATEMENT OF OPERATION AND RESOURCE UTILIZATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit B Statement of Operation and Resource Utilization

Exhibit B is a statement of project operation and resource utilization. If the project includes more than one dam with associated facilities, the information must be provided separately for each such discrete development. The exhibit must contain:

(1) A statement whether operation of the powerplant will be manual or automatic, an estimate of the annual plant factor, and a statement of how the project will be operated during adverse, mean, and high water years;

(2) An estimate of the dependable capacity and average annual energy production in kilowatt-hours (or a mechanical equivalent), supported by the following data:

(i) The minimum, mean, and maximum recorded flows in cubic feet per second of the stream or other body of water at the powerplant intake or point of diversion, with a specification of any adjustments made for evaporation, leakage, minimum flow releases (including duration of releases), or other reductions in available flow; monthly flow duration curves indicating the period of record and the gauging stations used in deriving the curves; and a specification of the period of critical streamflow used to determine the dependable capacity;

(ii) An area-capacity curve showing the gross storage capacity and usable storage capacity of the impoundment, with a rule curve showing the proposed operation of the impoundment and how the usable storage capacity is to be utilized;

(iii) The estimated hydraulic capacity of the powerplant (minimum and maximum flow through the powerplant) in cubic feet per second;

(iv) A tailwater rating curve; and

(v) A curve showing powerplant capability versus head and specifying maximum, normal, and minimum heads;

(3) A statement, with load curves and tabular data, if necessary, of the manner in which the power generated at the project is to be utilized, including the amount of power to be used on-site, if any, the amount of power to be sold, and the identity of any proposed purchasers; and

> (4) A statement of the applicant's plans, if any, for future development of the project or of any other existing or proposed water power project on the stream or other body of water, indicating the approximate location and estimated installed capacity of the proposed developments.

(1) Type of Operation

The Big Creek Nos. 1 and 2 powerhouses, located on Big Creek, can be operated locally from the control rooms at Powerhouse No. 1 or Powerhouse No. 2, or remotely from Big Creek Powerhouse No. 3 (FERC Project No. 120), which serves as the main control center for the entire BCS.

Project Operations

Operation of SCE's seven FERC-Licensed Projects in the Big Creek System (BCS) is managed from a watershed-wide perspective and on an individual project-by-project basis. The Big Creek Hydroelectric System consists of six major reservoirs (Thomas A. Edison, Florence, Huntington, Redinger, Shaver, and Mammoth Pool) and nine powerhouses (Portal; Eastwood; Mammoth Pool; and Big Creek Powerhouse Nos. 1, 2, 2A, 3, 4, and 8). Figure B-1 presents a schematic diagram of the seven FERC-Licensed Projects and associated reservoirs, water conveyance tunnels and powerhouses in the BCS. The operation of the BCS and the individual Projects is dependent on natural run-off during periods of snowmelt and wet weather and the operation of other components in the system, the amount of generation required for SCE's customers, and the dispatching of energy in accordance with the California Independent System Operator requirements.

SCE operates the four Big Creek ALP projects within the BCS in accordance with the FERC-license conditions, which includes minimum instream flow (MIF) release requirements that are made by SCE from diversions and impoundments.

The management of water through the BCS and specifically the four Big Creek ALP Projects routes water between Projects in a manner that best meets the operational constraints that are imposed either by contractual operating agreements (i.e., licenses, permits, etc.) or by physical limitations of the Project infrastructure. The BCS is subject to several operating constraints including the following: (1) available water supply; (2) electrical system requirements; (3) both planned and unplanned maintenance outages; (4) storage limits (including both recreation minimums and year-end carryover maximums); (5) both minimum and maximum release limits (from storage); (6) various provisions contained in water rights agreements; and (7) California Independent System Operator requirements.

Water Rights and Contractual Obligations

Each of SCE's Big Creek Hydroelectric Projects either has separate water rights or shares one or more water rights with other projects for the diversion, use, and storage of water. The majority of the water rights are for non-consumptive uses associated with the generation of power. A few locations, such as the SCE's administrative offices and company housing near Big Creek No. 1 Powerhouse have minor consumptive water rights. SCE does not hold water rights for the consumptive use of water by any party other than SCE, nor does SCE sell any water rights associated with the hydropower projects to other parties.

SCE's water rights were obtained pursuant to state law and a majority of the water rights are documented by licenses and permits issued to SCE, or its predecessors, by the State Water Resources Control Board (State Water Board). Additional water rights were obtained through appropriation of water prior to the implementation of the Water Commission Act of 1914, and by prescriptive use against other parties. SCE also holds other water rights as a riparian land owner, which authorizes SCE to divert and use water on land owned by SCE.

The water rights agreements contain stipulations that stem from the senior status of certain downstream water rights holders. Generally, any water right holder with senior rights began diverting water for consumptive purposes prior to SCE or its predecessors. To protect the rights of the downstream water rights holders, SCE entered into agreements that restrict the use of water within the BCS to non-consumptive purposes, i.e., hydroelectric generation. Certain agreements limit the length of time and amount of water that SCE can store in its Project reservoirs. In a few instances, SCE's non-consumptive water use is a senior water right, and other water users hold junior water rights.

SCE operates its reservoirs consistent with the Mammoth Pool Operating Agreement (MPOA), which specifies cumulative reservoir storage constraints based on the computed natural run-off for the water year at Friant Dam. The MPOA between SCE and the U.S. Bureau of Reclamation (Bureau) specifies water storage and release requirements for the BCS reservoirs, which are upstream of Friant Dam (Millerton Reservoir) and the associated Central Valley Project water distribution system operated by the Bureau on behalf of the downstream irrigators. Millerton Reservoir is a major irrigation storage facility serving the central San Joaquin Valley agricultural community. Meetings between SCE, the Bureau, and the downstream irrigators are held following the March 1 runoff forecast each year, and periodically as needed, to coordinate and optimize hydropower production consistent with irrigation needs of the downstream agricultural users holding senior water rights and emergency flood control operations of Millerton Reservoir. The MPOA includes constraints on the annual and seasonal timing and volume of releases from SCE's reservoirs, maximum year-end storage allowed, and minimum seasonal flow from Dam No. 7 (release and diversion).

BCS Water Management

A key component of the annual water management plan for the BCS is the development of an annual run-off forecast. The annual run-off forecast is developed based on snow pack and precipitation data collected in the vicinity of the Project. This information is used along with assumptions about future median precipitation and air temperatures to produce a run-off forecast through the end of the water year (September 30). The forecast includes an estimate of both the timing and the quantity of water that will enter Project reservoirs during that run-off season. Snow pack and precipitation data are shared with the California Department of Water Resources (DWR) and the Bureau, who use it to develop individual forecasts of run-off volumes and declare water year types (critical, dry, below normal, above normal, or wet). The run-off forecast is a valuable tool for planning and ensuring compliance with the constraints of the MPOA (described above) and for planning purposes. A majority of the MPOA and other constraints are based on actual run-off volumes. The forecast also is used for directing future operational plans for: 1) instream flow release requirements; 2) reservoir recreational storage requirements; and 3) hydroelectric generation operations for the entire BCS.

The operation of the BCS is similar in all water year types in that water diverted from Project reservoirs and diversions is utilized to generate power. There are subtle differences, however, in the way that the Project is operated during different water year types and during different conditions of state energy requirements.

Some of the BCS reservoirs generally spill in wet and above normal water years and are filled to maximum capacity when spill ceases. When the BCS reservoirs stop spilling, SCE is able to manage the system with available inflows and begin managing the water to meet electric supply requirements by providing both base load and peak cycling energy. In the upper basin area, water from the upper South Fork San Joaquin River drainage is stored in Florence Lake and water from Mono Creek drainage is stored in Lake Thomas A. Edison. Water is diverted from these two lakes and various other small backcountry diversions into Huntington Lake via the Ward Tunnel and the Mono-Bear Siphon. The volumes of water that can pass through Ward Tunnel and the siphon are limited by the physical size and layout of these conduits. Water deliveries to Huntington Lake are prioritized as follows: first priority is given to water from Florence Lake; second priority is given to water from Bear Diversion and Lake Thomas A. Edison; and third priority is given to water diverted from the small diversions at Camp 61 Creek, Camp 62 Creek, Chinquapin Creek and Bolsillo Creek. The water delivered to Huntington Lake may also pass through Portal Powerhouse at the exit of the Ward Tunnel depending upon the amount of water being transported.

BCS Power Generation

The BCS has three interlinked water chains or pathways through which water may be transported and used to produce power. The three water chains are:

- Huntington Water Chain: This chain consists of Portal Powerhouse, Powerhouse No. 1, Powerhouse No. 2, Powerhouse No. 8, Powerhouse No.3, and Powerhouse No. 4.
- Shaver Water Chain: This chain consists of Portal Powerhouse, Eastwood Power Station, Powerhouse No. 2A, Powerhouse No. 8, Powerhouse No. 3, and Powerhouse No. 4.
- Mammoth Water Chain: This chain consists of Mammoth Pool Powerhouse, Powerhouse No. 3, and Powerhouse No. 4.

After passing through or bypassing the Portal Powerhouse, water entering Huntington Lake is directed to either the Huntington Chain, or the Shaver Chain. If the generation from the powerhouses of either chain is increased or decreased proportionally, the changes in load will have no effect on the MIF, or total levels of the storage reservoirs and forebays within the BCS. Changes in total loading conditions of the two chains can, however, affect Florence Lake and Lake Thomas A. Edison and can affect the amount of water leaving the project at Powerhouse No. 4. If generation from the powerhouses of either chain is changed disproportionately, the levels of Huntington Lake, Shaver Lake, and Redinger Lake can be increased or decreased.

Water from Big Creek Powerhouse Nos. 1 and 2 in the Huntington Chain joins water from the Shaver Chain, which has already passed through Eastwood Power Station and Big Creek Powerhouse No. 2A, at the Big Creek Powerhouse No. 2 and 2A Tailrace (Dam 5). Water from these two chains is then diverted through Big Creek Powerhouse No. 8, after which it joins the waters of the San Joaquin River coming from the Mammoth Chain at the Big Creek No. 8 Tailrace (Dam 6 Impoundment). Water from all three chains then continues through Big Creek Powerhouse Nos. 3 and 4.

Waters from the Middle Fork and North Fork San Joaquin River (SJR) drainages, and the South Fork SJR flows not diverted at Florence Lake, Lake Thomas A. Edison, Bear Creek Forebay, and the small backcountry diversions, are collected in Mammoth Pool Reservoir and become part of the Mammoth Chain. Mammoth Pool Powerhouse is usually run at maximum during the high flow or run-off period to prevent or delay spill at Mammoth Pool Reservoir.

For the most part, Portal Powerhouse, Eastwood Power Station, and Big Creek No. 4 Powerhouse operate independently of the other powerhouses in the BCS. Portal Powerhouse opportunistically uses water passing through the Ward Tunnel for power generation, but only operates efficiently at moderate flows through Ward Tunnel. Ward Tunnel flows outside the efficient flow range of Portal Powerhouse bypass Portal Powerhouse through the Howell Bunger (HB) valve into Huntington Lake. Eastwood Power Station generation normally occurs during the peak demand period of the day, unless water is being moved continuously from Huntington Lake to Shaver Lake to avoid spill at Huntington Lake or to increase storage at Shaver Lake for use during peak periods. Maintaining storage (water surface levels) to maintain recreational needs at Huntington Lake and above pump-back minimum water surface level in Shaver Lake are important considerations when planning operations at Eastwood Power Station. Big Creek Powerhouse No. 4 is the last power generation opportunity in the Big Creek System and therefore adjustments in the operation of the Powerhouse No. 4 will not affect other upstream powerhouses in the BCS.

Generally, the three water chains of the BCS are operated around the clock in the spring run-off period, except in dry water years. Operational flexibility is limited during normal run-off because the amount of water run-off available exceeds the combined generation and storage capacity of the project, resulting in water flowing over spillways or “spill”.

After the end of the spill period, daily unit plant load schedules are established to maximize hydro resources during system peak load periods. When spring run-off is finished, if a powerhouse does not need to operate for water management, it is run preferentially during on-peak hours. Due to the nature of the energy market and SCE’s resources, it is generally beneficial for the Big Creek Projects to provide power during on-peak hours, once the spring run-off has finished. Since the BCS powerhouses discharge to reservoirs or forebays, the peaking operations generally do not cause varying flows in bypass reaches. Energy load changes on these power generation chains will not affect the water surface elevation (WSE) or instream flows, as long as adjustments are made to match reservoir inflows and outflows. A proprietary computer model used for predicting inflow is also used to plan monthly flow of water through the Project to meet the operating constraints on the system while maximizing generation during the peak load periods. In addition, computer programming of load schedules to use the most efficient units first, further enhances these operating activities and improves system integrity and efficiency. These activities can ensure the efficient use and availability of hydroelectric generation resources from these reservoir storage plants.

Market constraints and pricing, as well as transmission constraints and weather, will affect generation and operations at the Big Creek Projects. Often during the spring run-off season there is a financial disadvantage for SCE to generate energy even though to avoid generation would cause spill to occur. A simplified description of the California energy market describes the Independent System Operator (ISO) as having the role of balancing energy demand and supply in the state. The ISO takes the energy demand forecast, the transmission system constraints, and the energy that is bid into the day-ahead market to determine the acceptable energy supply. The ISO then adjusts the supply load on a real-time basis to account for changing conditions. If the ISO believes that there is a surplus of energy available beyond that necessary to supply the grid, prices in the California energy market for additional energy could be negative. This situation would require SCE to pay for contributing additional energy.

Water Management of Big Creek Nos. 1 and 2 Project (FERC Project No. 2175)

The water used by the Project is stored in Huntington Lake, which includes local run-off and water conveyed through Ward Tunnel from Florence Lake (FERC License No. 67), Lake Thomas A. Edison (FERC No. 2086), and from various small and intermediate size stream diversions. Powerhouse No. 1 utilizes water from Huntington Lake and discharges into the Dam 4 impoundment on Big Creek. Powerhouse No. 2 receives water from the Dam 4 impoundment and discharges to the Dam 5 impoundment on Big Creek.

The Big Creek Nos. 1 and 2 Project operates in conjunction with the rest of the BCS in a parallel and stair step sequence of water chains. Big Creek Powerhouses No. 1 and 2 represent the second and third generating opportunities in the Huntington water chain, respectively. The flow of water through the Powerhouse Nos. 1 and 2 Project is dependent on natural run-off during periods of snowmelt and wet weather and the operation of reservoirs in the BCS that are located at higher elevations within the drainage.

The operation of the Powerhouse Nos. 1 and 2 Project is similar in all water year types in that water diverted into the Project from remote impoundments and diversions is utilized to generate power when the water is available. In wet water years, the Project runs at full capacity beginning in mid-April to May until the end of peak run-off, which typically occurs in late July and SCE gains control of inflows. Then, SCE will manage powerhouse operations to meet base load requirements and/or peak cycling energy needs. Project generation is greater during wet water years and spills can occur at Dam 4.

In above normal water years, the Project is generally run at full capacity beginning in May until the end of peak run-off, which typically occurs in July. Some of the BCS reservoirs generally spill in above normal water years and are filled to maximum capacity until spill ceases. At that time, SCE gains control of inflows and begins managing the water to meet grid requirements by providing both base load and peak cycling energy.

During dry water years, the Project may run at full capacity for a short duration in May and June. In some dry water years, the Project does not run at full capacity in order to fill the reservoirs to maximum capacity. Project generation is lower in dry water years and very little water, other than required dam seepage and MIF releases, bypasses the powerhouses.

Under the Proposed Action, water management would remain generally the same as existing operations. However, under the Proposed Action, MIF's would be released from Dam 4, Balsam Creek Diversion, and Ely Creek Diversion.

(2) Capacity and Production

The installed operating capacity of the Project is rated at 154.85 MW and the dependable operating capacity is 150.0 MW. The average annual capacity factor for the Project between 1991 and 2005 was 56.4%. Over this period, the average annual capacity factors for Big Creek Powerhouses No. 1 and No. 2 were 53.3% and 60.6%, respectively. The annual Project generation output for Big Creek Powerhouses No. 1 and No. 2 and for the Project between 1991 and 2005 is provided in Table B-1.

Table B-1 Average Project Generation Output Between 1991-2005.

Year	Production in MWH (Transmitted)		
	PH No. 1	PH No. 2	Project Total
1991	284,011	241,640	525,651
1992	268,552	240,900	509,452
1993	523,600	453,101	976,701
1994	294,351	260,822	555,173
1995	549,019	481,493	1,030,512
1996	539,253	455,497	994,750
1997	628,022	493,720	1,121,742
1998	571,090	445,497	1,016,587
1999	390,999	337,212	728,211
2000	417,714	352,943	770,657
2001	254,827	226,988	481,815
2002	270,792	283,077	553,870
2003	375,743	318,385	694,128
2004	343,750	308,983	652,733
2005	476,404	393,857	870,261
15-year average =	**412,542**	**352,941**	**765,483**

(i) Daily average available flows – Powerhouse No. 1 utilizes water stored in Huntington Lake, which comes partially from high-elevation backcountry diversions through Ward Tunnel. Powerhouse No. 2 utilizes water diverted from Balsam and Ely Creeks and water from the impoundment formed by Dam 4 which includes throughput water from Powerhouse No. 1, as well as undiverted flows from Big Creek downstream of Huntington Lake and Pitman Creek. The following statistics represent the total available flow at the points of diversion associated with the project (Huntington Lake, Dam 4, and the Balsam Creek Diversion) with the exception of the Ely Creek Diversion for which the available data set, limited diversion flow data, is insufficient for analysis. Flows in both Balsam and Ely Creeks are available to SCE for diversion, but are not always diverted.

Huntington Lake (Dams 1-3)

The available flow at Huntington Lake represents flow available to both FERC Project No. 2175 and FERC Project No. 67. Flow utilized for Project No. 2175 is diverted through Powerhouse No. 1 and flow utilized for FERC Project No. 67 is diverted to North Fork Stevenson Creek or the Balsam Forebay through Tunnel 7 (FERC Project No. 67). The available flow at Huntington Lake was derived by adding the mean daily throughput flows for Powerhouse No. 1 (USGS Gage No. 11238100) and the mean daily flows through Tunnel 7 upstream of the Pitman Creek diversion. The flow data for Tunnel 7 was derived using the following methods: 1) for water year 1983, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the mean daily flow recorded at the Tunnel 7 outlet (USGS Gage No. 11239000); and, 2) for water years 1990 to 2002, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the sum of the Eastwood Powerstation throughput (USGS Gage No. 11237600) and flow in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300). The analysis for water years 1990 to 2002 overestimates available flow at Tunnel 7, since the flows recorded in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300) includes ungaged inflow upstream of the outlet. The period of record used in the analysis was October 1, 1982 to September 30, 1983 and October 1, 1989 to September 30, 2002. The flow statistics for Huntington Lake are presented below and the monthly flow duration curves are presented in Figure B-2.

Minimum	0 cfs
Median	681 cfs
Mean	790 cfs
Maximum	2,439 cfs

Dam 4

The available flow at Dam 4 was derived by adding the mean daily flow through Powerhouse No. 1 (USGS Gage No. 11238100) and the mean daily flow downstream of the Pitman Creek Diversion (USGS Gage No. 11237700). The period of record used for this analysis was October 1, 1982 to September 30, 1983 and October 1, 1984 to September 30, 2002. The flow statistics for Dam 4 are presented below and the monthly flow duration curves are presented in Figure B-3.

Minimum	0 cfs
Median	381 cfs
Mean	384 cfs
Maximum	1,452 cfs

Balsam Creek Diversion

The available flow at the Balsam Creek Diversion was derived using the mean daily flow data recorded at USGS Gage No. 11238270 which is located upstream of the diversion below the Balsam Forebay (FERC Project No. 67). The flow data does not account for accretion flows between the gage and the diversion. The period of record used for this analysis was January 24, 1989 to September 30, 2002. The flow statistics for the Balsam Creek Diversion are presented below and the monthly flow duration curves are presented in Figure B-4.

Minimum	0.31 cfs
Median	0.87 cfs
Mean	0.98 cfs
Maximum	3.40 cfs

(ii) Figure B-5 presents the area capacity-curves for Huntington Lake and Figure B-6 presents the area-capacity curves for the Dam 4 impoundment.

(iii) The total estimated maximum hydraulic capacity for the Project is 1,290 cfs and the total estimated minimum hydraulic capacity is 45 cfs. Big Creek No.1 unit 1 operates between 8 cfs and 152 cfs, Big Creek No.1 unit 2 operates between 6 cfs and 159 cfs, Big Creek No.1 unit 3 operates between 7 cfs and 150 cfs and Big Creek No.1 unit 4 operates between 10 cfs and 231 cfs. The Big Creek No.2 unit 3 operates between 4 cfs and 161 cfs, Big Creek No.2 unit 4 operates between 3 cfs and 142 cfs, Big Creek No.2 unit 5 operates between 5 cfs and 145 cfs and Big Creek No.2 unit 6 operates between 2 cfs and 150 cfs.

(iv) Tailwater rating curve – No gaging occurs in the tailrace of either the Big Creek No. 1 Powerhouse or Big Creek No. 2 Powerhouse since there is no effect from backwatering on the Project operations. The tailrace of Powerhouse No. 1 discharges into the Dam 4 impoundment and the tailrace of Powerhouse No. 2 discharges into the Dam 5 impoundment. Because there is no gaging at either of these discharge locations, there are no rating curves for the respective tailraces.

(v) Figures B–7 and B-8 present capability versus head curves for Big Creek Powerhouses No. 1 & 2, respectively.

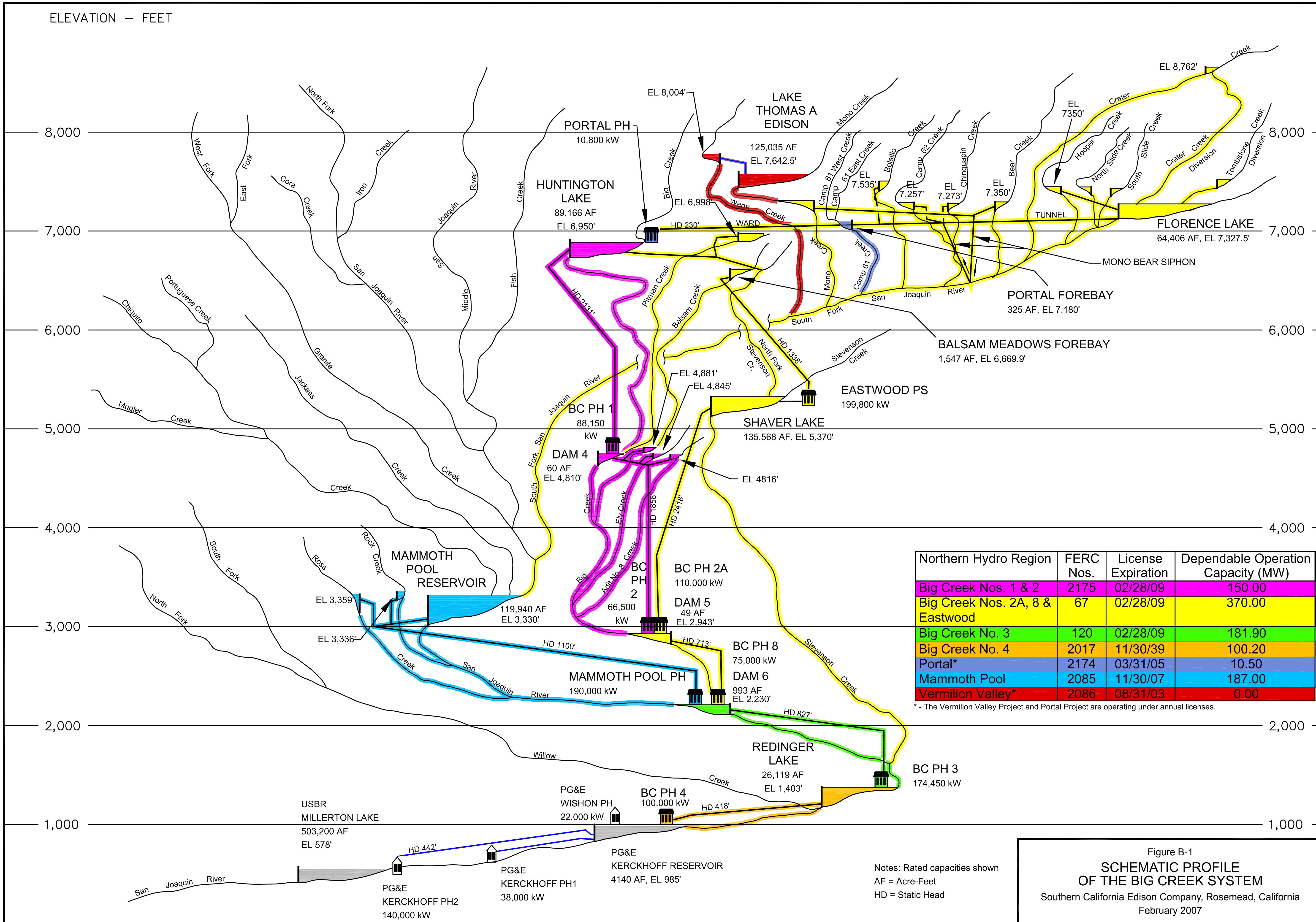
(3) Use of Generated Energy

The Big Creek Nos. 1 and 2 powerhouses operate as baseload facilities during the runoff season, and as peaking facilities the rest of the year. All energy generated, minus that necessary to operate the plant auxiliaries, is transmitted to SCE's electrical system. The amount of energy necessary to operate the Project auxiliaries averaged 51,072 KWh per month between 2001 and 2005. In regards to each powerhouse, the amount of energy necessary to operate the Powerhouse No. 1 auxiliaries averaged 25,826 KWh per month between 2001 and 2005 and the amount of energy necessary to operate Powerhouse No. 2 auxiliaries averaged 25,246 KWh per month between 2001 and 2005.

(4) Plans for Future Development

SCE has no current plans for any future development of the Project.

FIGURES

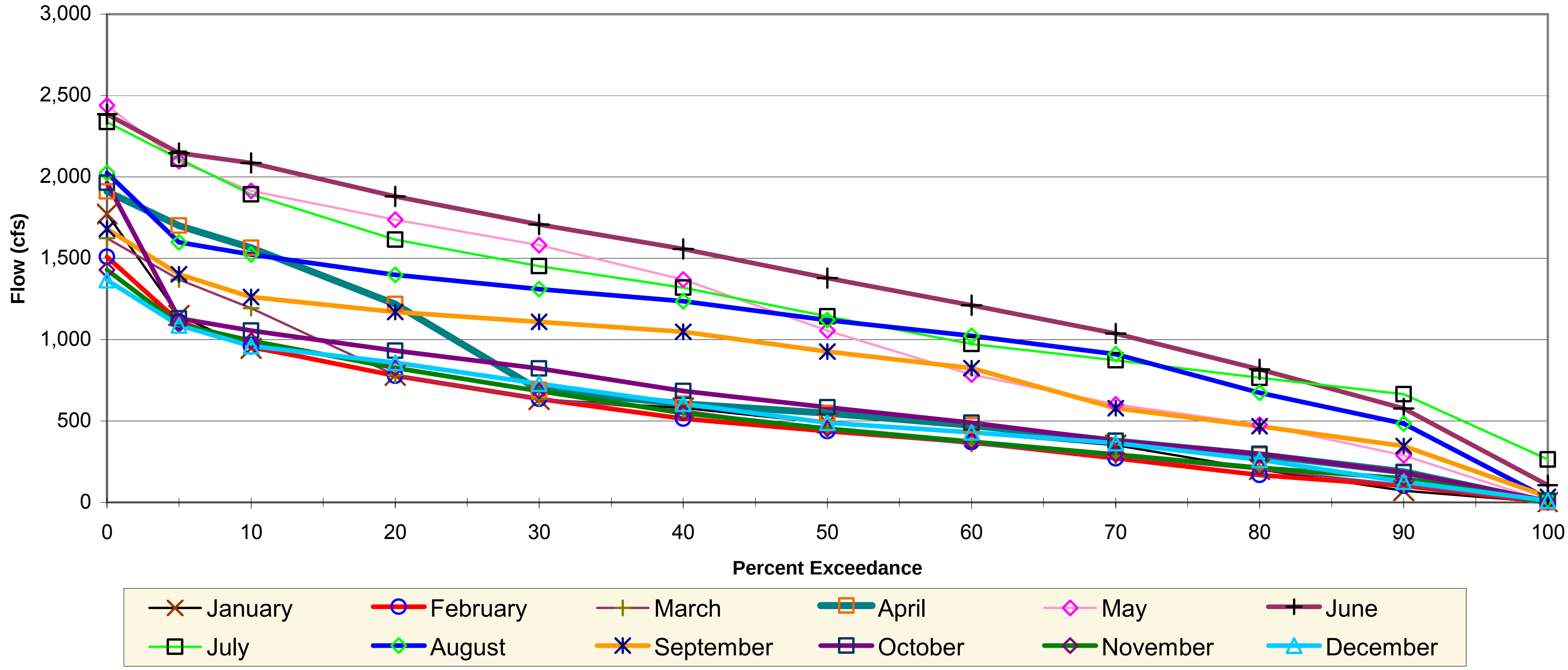


Northern Hydro Region	FERC Nos.	License Expiration	Dependable Operation Capacity (MW)
Big Creek Nos. 1 & 2	2175	02/28/09	150.00
Big Creek Nos. 2A, 8 & Eastwood	67	02/28/09	370.00
Big Creek No. 3	120	02/28/09	181.90
Big Creek No. 4	2017	11/30/39	100.20
Portal*	2174	03/31/05	10.50
Mammoth Pool	2085	11/30/07	187.00
Vermilion Valley*	2086	08/31/03	0.00

* - The Vermilion Valley Project and Portal Project are operating under annual licenses.

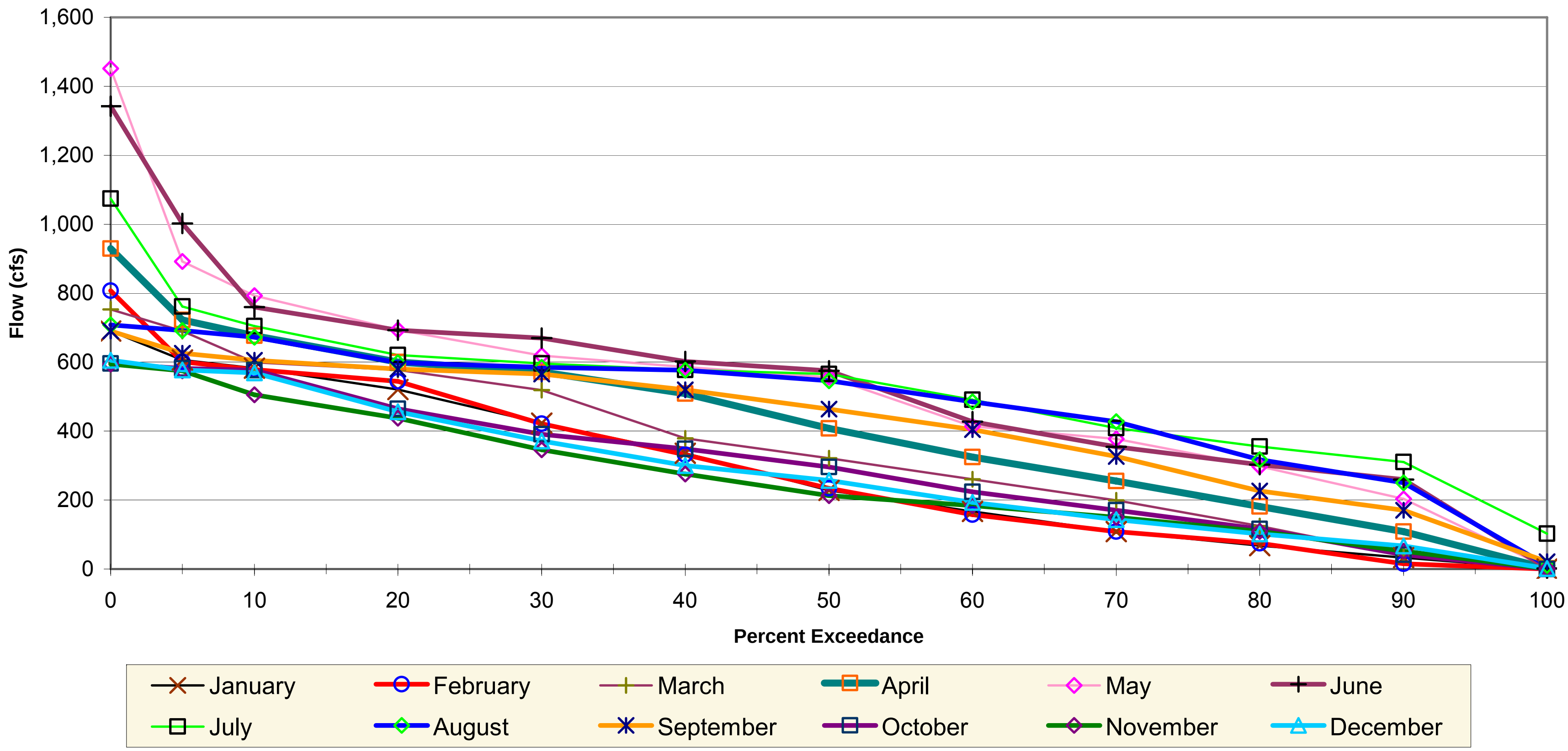
Notes: Rated capacities shown
AF = Acre-Feet
HD = Static Head

Figure B-1
SCHEMATIC PROFILE OF THE BIG CREEK SYSTEM
Southern California Edison Company, Rosemead, California
February 2007



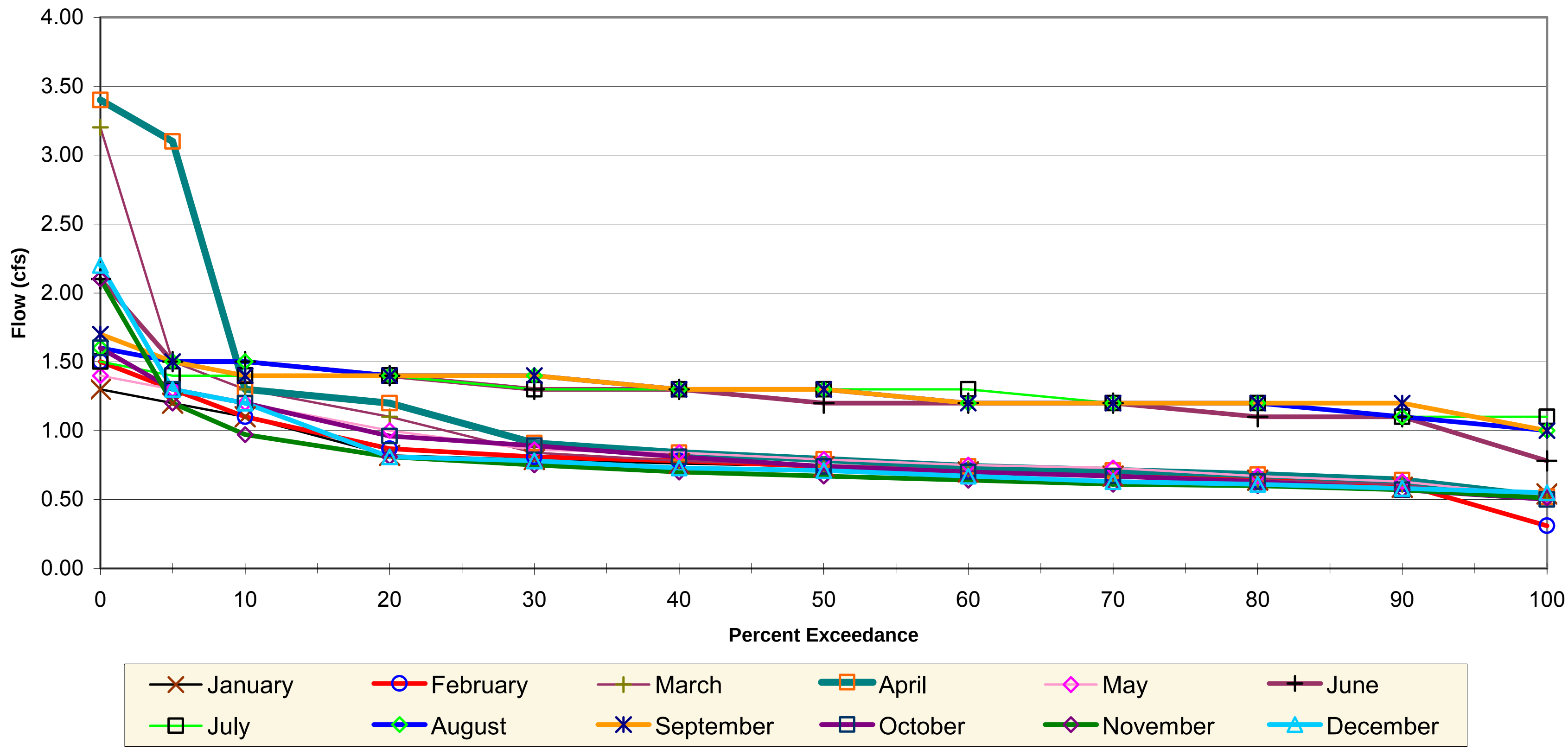
Note: Flows represent total available flow at Huntington Lake and were derived by adding the mean daily throughput flows for Powerhouse No. 1 (USGS Gage No. 11238100) and the mean daily flows through Tunnel 7 upstream of the Pitman Creek diversion. The flow data for Tunnel 7 was derived using the following methods: 1) for water year 1983, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the mean daily flow recorded at the Tunnel 7 outlet (USGS Gage No. 11239000); and, 2) for water years 1990 to 2002, the mean daily flows were calculated by subtracting the flow diverted at Pitman Creek (USGS Gage No. 11237600) and the minimum instream flow for North Fork Stevenson Creek from the sum of the Eastwood Powerstation throughput (USGS Gage No. 11237600) and flow in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300). The analysis for water years 1990 to 2002 overestimates available flow at Tunnel 7 since the flows recorded in North Fork Stevenson Creek downstream of the Tunnel 7 outlet (USGS Gage No. 11239300) include ungaged inflow upstream of the outlet. The period of record used in the analysis was October 1, 1982 to September 30, 1983 and October 1, 1989 to September 30, 2002.

Figure B-2. Monthly Flow Exeedance Curves at Huntington Lake.



Note: Flows represent total available flow at Dam 4 and were derived by adding the mean daily flow through Big Creek Powerhouse No. 1 recorded at USGS Gage No. 11238100 and the mean daily flow downstream of the Pittman Creek Diversion recorded at USGS Gage No. 11237700. The period of record used for this analysis was October 1, 1982 to September 30, 1983 and October 1, 1984 to September 30, 2002.

Figure B-3. Monthly Flow Exeedance Curves at Dam 4.



Note: Flows represent total available flow at the Balsam Creek Diversion and were derived using the mean daily flow data recorded at USGS Gage No. 11238270 which is located upstream of the diversion below the Balsam Forebay (FERC Project No. 67). The flow data does not account for accretion flows between the gage and the diversion. The period of record used for this analysis was January 24, 1989 to September 30, 2002.

Figure B-4. Monthly Flow Exeedance Curves at Balsam Creek Diversion.

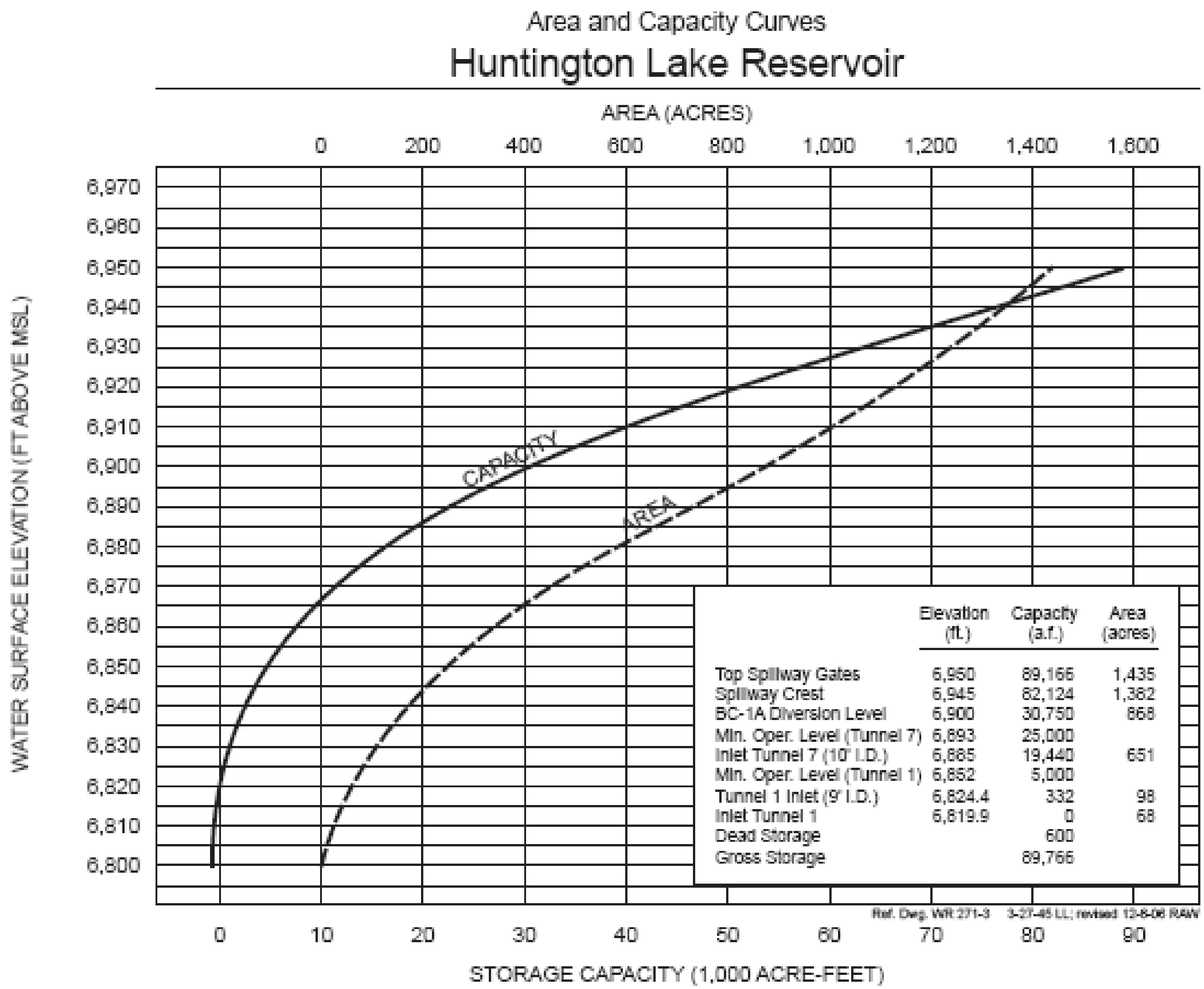


Figure B-5. Area and Capacity Curves. Huntington Lake Reservoir

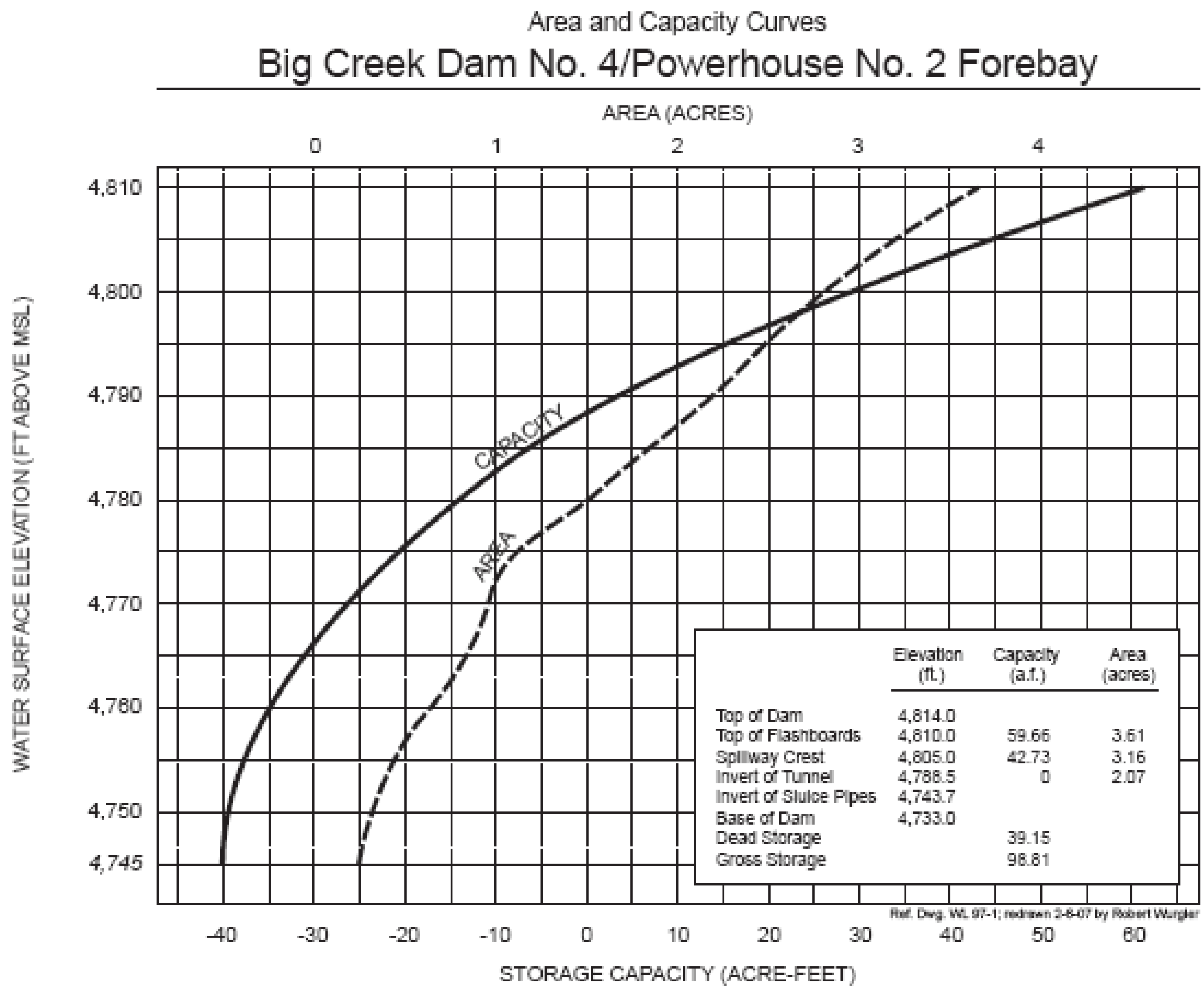


Figure B-6. Area and Capacity Curves. Big Creek Dam No. 4/Powerhouse No. 2 Forebay.

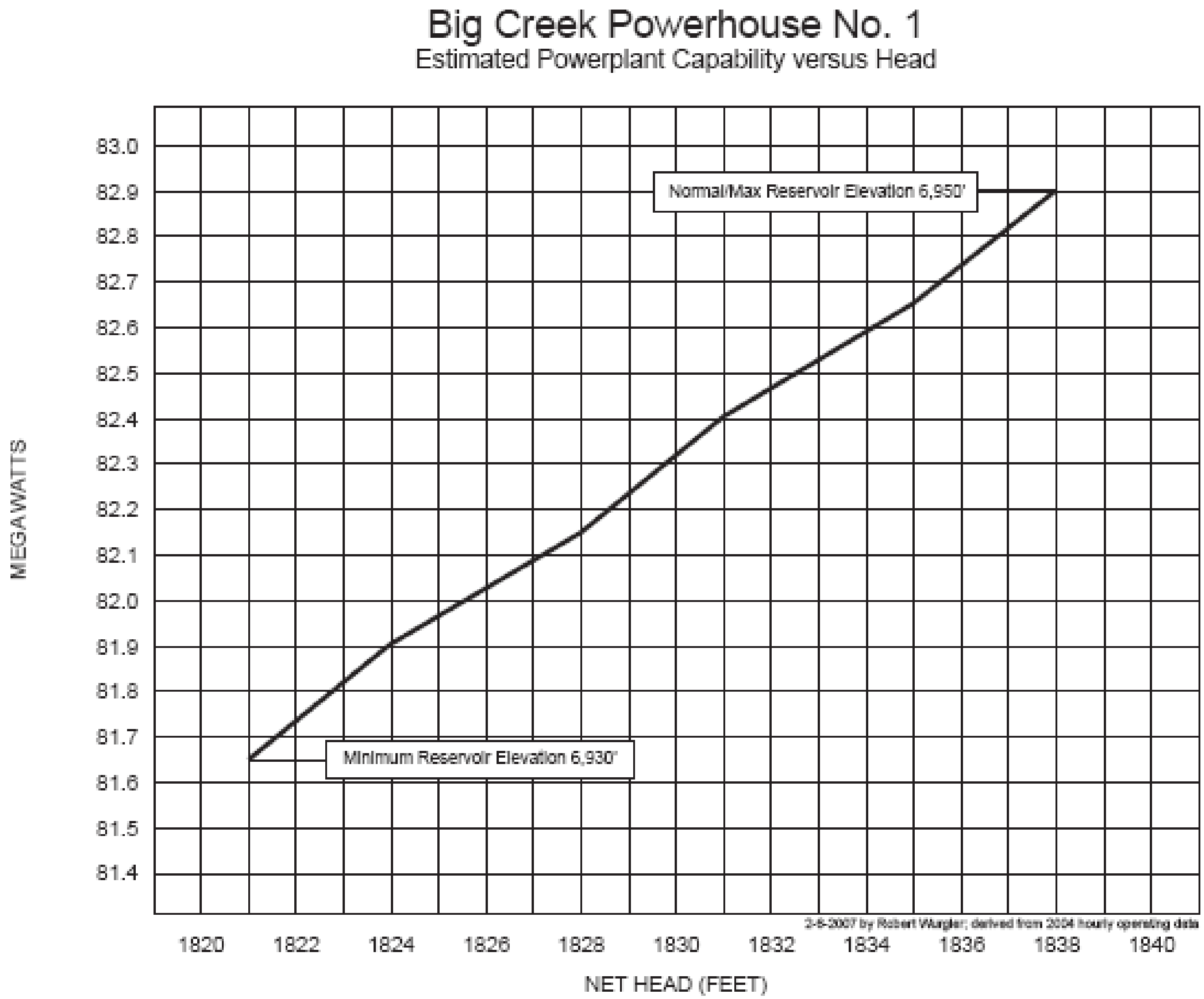


Figure B-7. Big Creek Powerhouse No. 1. Estimated Powerplant Capability Versus Head.

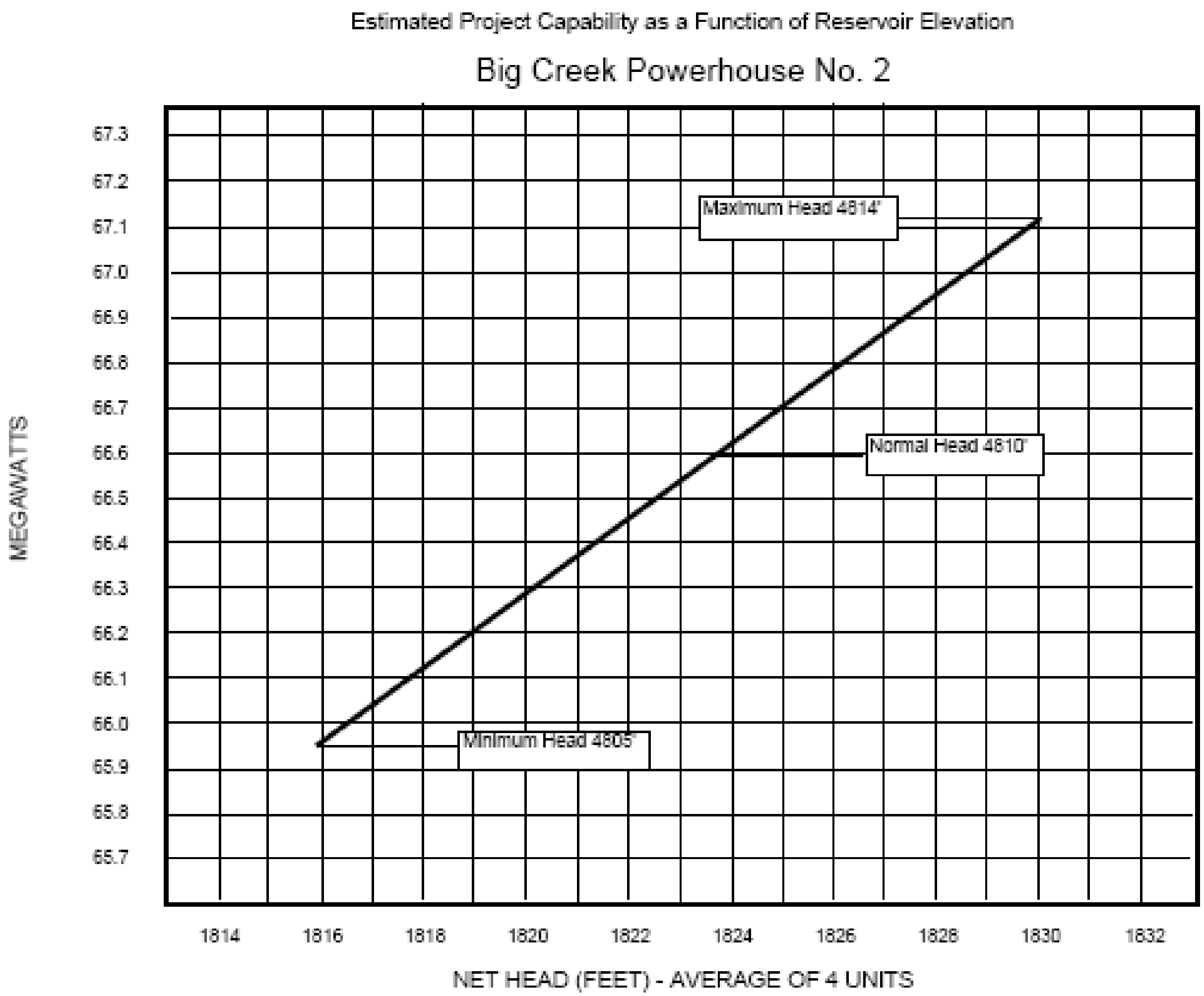


Figure B-8. Big Creek Powerhouse No. 2. Estimated Project Capability as a Function of Reservoir Elevation.

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 1 AND 2
(FERC Project No. 2175)

EXHIBIT C: CONSTRUCTION HISTORY

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit C Construction History and Proposed Construction Schedule

Exhibit C is a construction history and proposed construction schedule for the project. The construction history and schedules must contain:

> (1) If the application is for an initial license, a tabulated chronology of construction for the existing projects structures and facilities described under paragraph (b) of this section (Exhibit A), specifying for each structure or facility, to the extent possible, the actual or approximate dates (approximate dates must be identified as such) of:
>
> (i) Commencement and completion of construction or installation;
>
> (ii) Commencement of commercial operation; and
>
> (iii) Any additions or modifications other than routine maintenance; and
>
> (2) If any new development is proposed, a proposed schedule describing the necessary work and specifying the intervals following issuance of a license when the work would be commenced and completed.

(1) **Construction History**

(i) This Application is for a new license and not for an initial license. The Project was constructed between 1912 and 1917 as follows:

- The initial phase of construction for Dams No. 1, 2, and 3 commenced in the Summer of 1912 and was completed in the Fall of 1913.
- Dam No. 4 was constructed in 1913.
- The construction of Powerhouse 1 commenced in the spring of 1913 and was completed in October 1913.
- The construction of Powerhouse 2 commenced in the spring of 1913 and was completed in December 1913.
- The second phase of Project construction occurred in 1917 and consisted of increasing the crest height of Dams No. 1, 2, and 3 by 38 feet and the construction of Dam No. 3A.

(ii) The commencement of commercial operation for the Project powerhouses occurred on the following dates:

- Powerhouse No. 1 Unit 2 commenced operation on November 8, 1913. Unit 1 commenced operation on November 9, 1913 and Units 3 and 4 went online on July 12, 1923 and June 8, 1925, respectively.

- Powerhouse No. 2 Unit 3 commenced operation on December 18, 1913. Unit 4 went into service on January 11, 1914. Unit 5 went into service on February 1, 1921. Unit No. 6 went into service on March 31, 1925.

(iii) The Project has undergone the following upgrades and modifications since start-up:

Dam 1

- In 1917, Dam 1 was raised an additional 38 feet, a concrete siphon spillway was constructed near the right abutment, and a system of open joint, vitrified clay, drain pipe was installed in the concrete when raising the dam.

- In 1937 and 1938, the following activities were conducted at Dam 1: compacted earth fill was placed on the downstream side of the dam along the full length of the dam to the crest; a new auxiliary spillway was constructed through the granite rock west of the western abutment; a 4-inch drainage outlet was installed; a portion of the upstream face of the dam was sealed with gunite; and, a portion of the foundation was grouted.

- In 1939, a portion of the upstream face of Dam 1 was replaced with gunite and mesh reinforcement.

- Between 1945 and 1946, compacted earth fill was placed against the upstream left abutment of Dam 1 to elevation 6,930 feet msl.

- In 1955, compacted earth fill was placed against the upstream left abutment of Dam 1 to crest elevation of 6,953.5 feet msl.

- In 1955, steel sheet facing, backfilled with a minimum thickness of 0.5 feet of concrete, was placed along the exposed upstream surface of Dam 1 above elevation 6,850 feet msl to the crest elevation of 6,953.5 feet msl.

- In 1964, restoration of the wooded cribbing around the sluice gate operator platform at Dam 1 was performed.

- In 1971, leaks were repaired at the peripheral seal of the steel facing and the facing repainted.

- In 1971, a new lake level recorder was installed.

- In 1980, leaks were repaired at the peripheral seal of the steel facing.

- In 1984, the boulder-faced embankment “parapet” on the downstream side of the dam crest was coated with gunite.

Dam 2

- In 1917, Dam 2 was raised an additional 38 feet, and a system of open joint, vitrified clay, drain pipe was installed in the concrete when raising the dam.
- In 1937, compacted earth fill was placed on the downstream side of the dam along the full length of the dam to the crest, a 4-inch drainage outlet was installed, and a portion of the upstream face of the dam was sealed with gunite.
- Between 1945 and 1946, compacted earth fill was placed against the upstream abutment section of Dam 2 to elevation 6,930 feet msl.
- In 1955, compacted earth fill was placed against the upstream abutment section of Dam 2 to crest elevation of 6,953.5 feet msl.
- In 1955, steel sheet facing, backfilled with a minimum thickness of 0.5 feet of concrete, was placed along a portion of the upstream surface of Dam 1 above elevation 6,895 feet msl to the crest elevation of 6,953.5 feet msl.
- In 1971, gunite repairs were made to about 115 lineal feet of seal at the periphery of the steel facing and extensive repairs were made to 120 sq. ft. of the area around and behind the intake rack and trash rack.
- In 1971, the 4-inch pipe from the drainage system for the steel facing was removed and replaced with a 6-inch pipe that was grouted into place.
- In 1971, leaks were repaired at the peripheral seal of the steel facing and the facing was repainted.
- In 1971, a new lake level recorder was installed.
- In 1984, the existing boulder “parapet” on the downstream side of the dam crest was coated with gunite.

Dam 3

- In 1917, Dam 3 was raised an additional 38 feet, and a system of open joint, vitrified clay, drain pipe was installed in the concrete when raising the dam.
- In 1929, compacted earth fill was placed against the abutment section of dam to elevation 6,915 feet msl.

- Between 1936 and 1937, compacted earth fill was placed on the downstream side of the dam along the full length of the dam to the crest and a 4-inch drainage outlet was installed.

- In 1937, compacted earth fill was placed against the upstream abutment section of Dam 3 to elevation 6,920 feet msl.

- In 1945, compacted earth fill was placed against the upstream abutment section of Dam 3 to elevation 6,930 feet msl.

- In 1966, an overhanging eave was constructed at the dam crest to deflect snow melt and inhibit the formation of ice on the upstream concrete face exposed above the embankment.

- In 1984, the boulder-faced embankment “parapet” on the downstream side of the dam crest was coated with gunite.

Dam 3A

- In 1917, Dam 3A was constructed.

- Between 1936 and 1937, compacted earth fill was placed on the downstream side of the dam along the full length of the dam to the crest. The fill was covered with large riprap to an elevation of 6,956 feet msl.

- In 1938, compacted earth fill was placed against the upstream face of the dam to an approximate elevation of 6,945 feet msl.

- Between 1938 and 1939, the dam foundation was regrouted.

- In 1966, the exposed upstream concrete face of the dam was repaired and compacted earth fill was placed against the upstream face to the crest of the dam.

- In 1967, the backfill was placed along the upstream side of the dam to increase the width of the crest to 15 feet in front of the concrete dam.

- In 1984, the existing boulder “parapet” on the downstream side of the dam crest was coated with gunite.

Dam 4

- In 1940, the downstream face was sealed with gunite and a drainage system was installed beneath the gunite seal.

- In 1976, an overhead trolley was installed, with steel supports to permit more efficient handling of flashboards.

- In 2000, a new automated trash rake was installed at the intake structure.

Turbines

- In 1986, Powerhouse No. 1 Unit 4 was upgraded from 35,000 HP to 42,100 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

- In 1989, Powerhouse No. 1 Unit 2 was upgraded from 20,000 HP to 28,060 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

- In 1989, Powerhouse No. 2 Unit 4 was upgraded from 20,000 HP to 27,270 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

- In 1991, Powerhouse No. 2 Unit 3 was upgraded from 20,000 HP to 27,270 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

- In 1993, Powerhouse No. 1 Unit 1 was upgraded from 20,000 HP to 29,025 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

- In 1994, Powerhouse No. 1 Unit 3 was upgraded from 22,500 HP to 29,025 HP. In addition, the original turbine, which was designed for 50-cycle operation and utilized bolted buckets was replaced with integral cast stainless steel wheels.

Generators

- In 1941, Powerhouse No. 1 Generator 4 was rewound.

- In 1947, Powerhouse No. 1 Generator 2 was rewound.

- In 1947, Powerhouse No. 2 Generator 6 was rewound.

- In 1948, Powerhouse No. 1 Generator 1 was rewound and upgraded from 14,000 kW to 19,800 kW.

- In 1951, Powerhouse No. 1 Generator 3 was rewound.

- In 1971, Powerhouse No. 1 Generator 4 was rewound and upgraded from 25,000 kW to 31,200 kW.
- In 1985, Powerhouse No. 2 Generator 5 was upgraded from 14,000 kW to 17,500 kW.
- In 1985, Powerhouse No. 2 Generator 6 was upgraded from 15,750 kW to 17,500 kW.
- In 1989, Powerhouse No. 2 Generator 4 was upgraded from 14,000 kW to 15,750 kW.
- In 1989, Powerhouse No. 1 Generator 2 was rewound and upgraded to 15,750 kW.
- In 1989, the pilot exciters for the Powerhouse No. 1 generators were upgraded to solid state.
- In 1991, Powerhouse No. 2 Generator 3 was upgraded from 14,000 kW to 15,750 kW.
- In 1993, Powerhouse No. 1 Generator 1 was rewound.
- In 1994, Powerhouse No. 1 Generator 3 was rewound and upgraded from 14,000 kW to 21,600 kW.
- In 1998, Powerhouse No. 1 Generator 4 was rewound and upgraded from 28,000 kW to 31,200 kW.
- In 2003, Powerhouse No. 2 Generator 5 was rewound.
- In 2006, Powerhouse No. 2 Generator 6 Rotor Pole was rewound.

(2) New Development

This is an existing project, but new construction activities are proposed that allow establishment of or increase in Minimum Instream Flow releases at Dam 4, and at the Balsam and Ely creek diversions, and associated stream gaging facilities. No other new construction activities are planned, except those which occasionally arise during the course of routine operation and maintenance of the Project.

SCE will evaluate the likely construction approach, and access needs for each facility to determine the appropriate infrastructure modification and to complete the preliminary engineering work for the modification. Based on this preliminary work, SCE will obtain necessary permits from resource agencies other than FERC prior to construction of the infrastructure modification. The following summarizes the needed infrastructure improvements and the preliminary schedule to design and construct these improvements.

- Dam 4. A release structure and flow measurement device would need to be installed. The schedule for this work is estimated as follows: preliminary engineering and site evaluation would be conducted in 2008; engineering and permitting would be conducted in 2009; continued engineering and equipment ordering would be conducted in 2010; and the construction would begin in 2011 and possibly continue into 2012.

- Balsam Creek Diversion Dam. A release structure and flow measurement device would need to be installed. The schedule for this work is estimated as follows: preliminary engineering and permitting would be conducted in 2008; engineering and equipment ordering would be conducted in 2009; and the construction would begin in 2010 and possibly continue into 2011.

- Ely Creek Diversion Dam. A release structure and flow measurement device would need to be installed. The schedule for this work is estimated as follows: preliminary engineering and permitting would be conducted in 2008; engineering and equipment ordering would be conducted in 2009; and the construction would begin in 2010 and possibly continue into 2011.

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 1 AND 2
(FERC Project No. 2175)

EXHIBIT D: PROJECT COSTS AND FINANCING

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit D Project Costs and Financing

Exhibit D is a statement of costs and financing. The statement must contain:

(1) If the application is for an initial license, a tabulated statement providing the actual or approximate original cost (approximate costs must be identified as such) of:

(i) Any land or water right necessary to the existing project; and

(ii) Each existing structure and facility described under paragraph (b) of this section (Exhibit A).

(2) If the Applicant is a licensee applying for a new license, and is not a municipality or a state, an estimate of the amount which would be payable if the project were to be taken over pursuant to section 14 of the Federal Power Act upon expiration of the license in effect [*see* 16 U.S.C. 807], including:

(i) Fair value;

(ii) Net investment; and

(iii) Severance damages.

(3) If the application includes proposals for any new development, a statement of estimated costs, including:

(i) The cost of any land or water rights necessary to the new development; and

(ii) The cost of the new development work, with a specification of:

(A) Total cost of each major item;

(B) Indirect construction costs such as costs of construction equipment, camps, and commissaries;

(C) Interest during construction; and

(D) Overhead, construction, legal expenses, taxes, administrative and general expenses, and contingencies.

(4) A statement of the estimated average annual cost of the total project as proposed specifying any projected changes in the costs (life-cycle costs) over the estimated financing or licensing period if the applicant takes such changes into account, including:

(i) Cost of capital (equity and debt);

(ii) Local, state, and Federal taxes;

(iii) Depreciation or amortization;

> (iv) Operation and maintenance expenses, including interim replacements, insurance, administrative and general expenses, and contingencies; and,
>
> (v) The estimated capital cost and estimated annual operation and maintenance expense of each proposed environmental measure.
>
> (5) A statement of the estimated annual value of project power, based on a showing of the contract price for sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source, specifying any projected changes in the cost of power from that source over the estimated financing or licensing period if the applicant takes such changes into account.
>
> (6) A statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e) (3) and (4) of this section.
>
> (7) An estimate of the cost to develop the license application;
>
> (8) The on-peak and off-peak values of project power, and the basis for estimating the values, for projects which are proposed to operate in a mode other than run-of-river; and
>
> (9) The estimated average annual increase or decrease in project generation, and the estimated average annual increase or decrease of the value of project power, due to a change in project operations (*i.e.,* minimum bypass flows; limits on reservoir fluctuations).

(1) <u>Original Cost</u>

Original cost of Project construction and obtaining land and water rights does not apply because the Project, which includes Big Creek 1 and Big Creek 2 powerhouses, is not an application for an initial license and all necessary water rights and privately-owned lands have already been obtained.

(i) Not Applicable.

(ii) Not Applicable.

(2) <u>Takeover Cost</u>

It is the intent of SCE to continue to operate the Project upon receipt of a new license. If the Project were to be taken over at the expiration of the existing license, the following values would apply.

(i) The fair value of the Project is estimated to be $342.4 million in 2006 dollars. The fair value of the project was determined by calculating the net benefits realized by customers from a revenue requirement perspective. The calculation nets the full capital recovery and operating costs against the energy and capacity benefits of the project. Energy benefits are defined as the value of replacement marginal-cost market energy. Capacity benefits are defined as the deferral value of a combustion turbine (CT), given the least-cost characteristics of a CT for a capacity-only product with no associated energy benefits. These values were calculated on an annual basis and present valued to determine the fair value of the project.

(ii) The Net Investment of the Project was $39,594,897 as of December 31, 2005.

(iii) The severance value for the 765,483 MWh of annual generation is $342.4 million and equal to the Fair Value discussed above in D(2)(ii) (also see Attachment D-1).

(3) Cost of New Development

The costs of new development do not apply because this Application does not include any such proposals. Only upgrades to existing facilities are planned and these will be performed during routine maintenance, or as planned capital replacement, or as structural modifications consistent with any new license requirements. Infrastructure changes required to implement environmental measures are discussed below in D(4)(v) (also see Attached D-2).

(i) Not Applicable.

(ii) Not Applicable.

(A) Not Applicable.

(B) Not Applicable.

(C) Not Applicable.

(D) Not Applicable.

(4) Cost of Financing

The annual costs for this Project include expenses for Operations and Maintenance (O&M) as well as capital improvement work. The work currently scheduled for this Project is plant upgrades and maintenance, not “new development.”

(i) The current SCE Cost of Capital is listed below:

Long-Term Debt	3.14%
Preferred Equity	0.75%
Common Equity	6.11%
Total Cost of Capital	10.00%

(ii) Property Taxes associated with this Project for 2005 were $425,702. State and Federal income taxes are computed for all of the SCE Hydro assets combined and no amount is specifically designated for this individual Project.

(iii) Depreciation for the Project for 2005 was $ 1,441,469.

(iv) The direct O&M expenses for this Project are $7,107,462, which is an estimated annualized value for the life of the license. Approximately $533,704 of these O&M expenses are represented by annual fees that are detailed in Exhibit H(b)(9). Additional expenses not mentioned above include Administrative and General (A&G) expenses. These expenses are calculated for all of the SCE Hydro assets combined. An approximation of A&G expenses is equal to 1.25% times the Net Plant Investment or $494,936 per year.

(v) The estimated capital cost and estimated annual operation and maintenance expense of each proposed environmental measure is listed in Attachment D-2 and totals $1,223,477 as an annualized value.

(5) Value of Project Power

SCE procures energy and related products to cover its “net-short” energy requirements for its electricity customers. The “net-short” position is defined as the condition when the energy required to meet customer demand exceeds the energy that SCE can provide from its owned or contracted resources.

The Project’s projected annual power value is determined by estimating the cost of replacing the energy and capacity provided by this Project at SCE’s current forecast of the marginal cost for energy and capacity. The estimated annual amount of energy produced from the Project was derived from a 15-year annual average of historical production from 1991 to 2005.

The amount of average annual replacement energy (MWh’s) for the Project was multiplied by the marginal energy cost forecast, and the capacity of the Project was multiplied by the marginal capacity cost forecast. The sum of the replacement energy and capacity costs is the total cost that SCE would expect to incur to replace the power being provided by this Project. The generation marginal costs used in these calculations were obtained from SCE’s 2006 General Rate Case (GRC) filing. Since that forecast does not include information beyond 2008, it is assumed that the costs will increase according to the Gross Domestic Product (GDP) Price Index escalation. SCE used an estimate of escalation from Global Insight (formerly DRI-WEFA) for the years beyond 2008.

This Project's forecasted power value for 2009 is $51.2 million. When the power value is escalated for the expected 44-year term of the license and discounted at the SCE cost of capital, it yields a net present value of $505.7 million in 2006 dollars. The levelized annual value of the energy benefits is $51.2 million (see Attachment D-3).

(6) Sources of Financing and Revenues

As previously discussed in Exhibit D(3), there is no major new development planned for this Project. As such, there is no need to acquire special financing for any major capital work.

SCE previously filed a 2006 GRC with the California Public Utilities Commission (CPUC) in September 2005, which was approved in May of 2006. Included in this Rate Case filing were the generation-related O&M expenses as well as A&G expenses. The 2006 GRC filings included the expected costs for the years of 2006–2008, which are associated with the operation and maintenance of all the SCE Hydro assets, as well as the costs associated with any anticipated incremental capital additions. SCE is preparing to file a 2009 GRC Notice of Intent (NOI) with the CPUC in 2007. Assuming that the 2009 Rate case is approved, the capital and O&M expenses necessary for continued operation of the Projects will be collected through those approved rates. Those approved rates will include costs associated with license condition requirements that might be imposed upon the Projects in this license application in the years 2009-2011.

This Project is operated as a component of the entire Hydro Generation Division, which is part of the Power Production Department of SCE. The O&M expenses for this Project are therefore not wholly estimated at the division or department level, as the departmental costs are usually extrapolated from historical costs. Any financing charges required for individual projects would normally be included in the overall department budget and would not be directly attributable to the individual Project.

(7) License Application Development Cost

The cost incurred for this Project's FERC license Application through December, 2006 is approximately $10,741,000. These costs include development of the license Application including portions of the Amended Preliminary Draft Environmental Analysis (APDEA), which includes Projects 2175, 2085, 67, and 120 as part of the Alternative Licensing Process (ALP) started in 2000.

(8) Value of On-Peak and Off-Peak Project Power

The on-peak and off-peak power values for the Project are based upon the 2006 energy price of $49.40 per megawatt-hour (MWh) and the 2006 capacity price of $69.70 per kilowatt-year (kW-year). In 2007, the on-peak period energy price is $56.63/MWh and the associated off-peak energy price is $42.48/MWh. The distribution of the total power value is based on the ratios of on-peak to off-peak energy and capacity values. Energy value is distributed between on- and off-peak based on ratios developed while creating hourly fundamental energy price forecasts. Capacity value is distributed based on SCE's relative loss-of-load probability factors. Both sets of factors are consistent with those presented in Phase 2 of SCE's 2006 General Rate Case.

Attachment D-4 provides the average annual Project generation for dry, normal, and wet year categories. The total generation is divided into on-peak and off-peak generation. The percentages of time that the powerhouse operated in on-peak and off-peak generation modes was calculated using hourly generation data from the years 2001 (dry), 2000 (normal), and 2005 (wet). These calculated percentages of on-peak and off–peak powerhouse operation were applied to average annual generation to determine the average generation value of on-peak and off-peak generation in megawatt-hours. This analysis was conducted for dry, normal and wet years as defined in the footnote to Attachment D-4.

(9) Effects of Changes in Project Operations

Under the Proposed Action, it is estimated that the average annual project generation will decrease by 108,411 MWh, resulting in a net reduction in the value of project power of approximately $5,683,000 (this is an annualized value in 2006$ based on the anticipated power generation over a projected 44-year license term).

ATTACHMENT D-1

FERC Project No. 2175 - Fair Value

ATTACHMENT D-1

Big Creek 1 & 2 - Project 2175 Fair Value

Revenue Requirement Net Present Value Benefit **$342,386** **(In $2006)**
(In $Thousands)

Year	Project Costs ($)	Energy Benefits ($)	Capacity Benefits ($)	Net Benefits ($)
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	9,572	40,108	11,089	41,624
2010	11,204	40,922	11,314	41,032
2011	12,830	41,797	11,556	40,522
2012	14,716	42,670	11,797	39,751
2013	15,786	43,525	12,034	39,772
2014	16,858	44,369	12,267	39,778
2015	17,812	45,202	12,497	39,887
2016	18,729	46,032	12,727	40,029
2017	19,295	46,853	12,954	40,511
2018	20,138	47,652	13,175	40,688
2019	20,958	48,515	13,413	40,971
2020	21,667	49,410	13,661	41,404
2021	22,541	50,333	13,916	41,708
2022	23,142	51,273	14,176	42,307
2023	23,905	52,241	14,443	42,779
2024	24,672	53,223	14,715	43,266
2025	25,402	54,241	14,996	43,836
2026	26,259	55,289	15,286	44,316
2027	27,138	56,351	15,580	44,793
2028	27,749	57,427	15,877	45,554
2029	28,611	58,548	16,187	46,124
2030	29,546	59,692	16,504	46,650
2031	30,518	60,848	16,823	47,153
2032	31,555	62,016	17,146	47,608
2033	32,810	63,194	17,472	47,855
2034	33,714	64,391	17,803	48,480
2035	34,813	65,602	18,138	48,927
2036	36,105	66,838	18,479	49,212
2037	37,067	68,097	18,827	49,857
2038	38,101	69,380	19,182	50,461
2039	39,321	70,686	19,543	50,908
2040	40,006	72,018	19,911	51,924
2041	41,101	73,374	20,286	52,560
2042	42,382	74,756	20,669	53,043
2043	43,708	76,165	21,058	53,514
2044	45,282	77,599	21,454	53,772
2045	47,185	79,061	21,859	53,734
2046	49,986	80,550	22,270	52,834
2047	54,002	82,067	22,690	50,755
2048	58,705	83,613	23,117	48,025
2049	64,318	85,188	23,553	44,422
2050	71,452	86,792	23,996	39,337
2051	82,327	88,427	24,448	30,548
2052	85,681	90,093	24,909	29,320
Total	**$1,498,671**	**$2,726,425**	**$753,798**	**$1,981,553**
NPV	**$163,356**	**$396,201**	**$109,541**	**$342,386**

(All above are $Thousands)

Assumptions:

Energy and Capacity value per Appendix D-2
Project costs are based on Revenue Requirements
SCE Cost of Capital: 10.00%
License Life: 44 years

ATTACHMENT D-2

Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 1 and 2 Project (FERC Project No. 2175)

Attachment D-2. Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 1 and 2 Project (FERC Project No. 2175).

Environmental Measures	Year(s) Implemented	Capital and One-Time Costs (2006$)	Annual Costs Including O&M (2006$)	Annualized Costs (2006$)	Reduction in Annual Energy Benefits (2006$)
WATER AND AQUATIC RESOURCES					
Implement New Minimum Instream Flow and Channel Riparian Maintenance Flow Releases	3-46		$2,000	$1,806	$5,683,000
Maintain Existing and New Gaging Stations	3-46		$100,000	$90,313	
Complete Required Infrastructure Modifications (MIF releases and gaging)					
Ely Creek Diversion (core dam install float gage)	4-7	$350,000		$21,903	
Balsam Creek Diversion Infrastructure Changes (core dam install float gage)	4-7	$350,000		$21,903	
Dam 4 Infrastructure Changes (core dam , install release structure and AVM gage)	4-7	$2,500,000		$156,450	
Implement Monitoring Programs					
Temperature	8-12		$40,000	$9,229	
Flow	3-46		$50,000	$45,157	
Fish	3,10,20,30,40		$50,000	$7,176	
Implement Sediment Management Plan					
Small Diversion (pass through)	Every 3rd year, beginning 2009		$2,500	$817	
Dam 4 (Flush) and V* Monitoring	Every 5th year, beginning 2012		$25,000	$4,148	
Attend Annual Consultation Meeting	3-46		$500	$452	
TERRESTRIAL RESOURCES					
Implement Wildlife Habitat Enhancement	3-46		$2,000	$1,806	
Implement Management Plans					
Bald Eagle	Every 5 years, beginning 2009		$10,000	$2,118	
Vegetation and Integrated Pest	3-46		$50,000	$45,157	
Implement Proposed License Articles (Special-status Species, Bats, Bear-Human)	3-46	$2,000	$6,000	$5,563	
Implement Environmental Programs (Environmental Training, ESAP, Avian, Noxious Weed, NHSSIP, Environmental Compliance)	3-46	$25,000	$2,500	$4,065	
Attend Annual Consultation Meeting	3-46		$500	$452	
RECREATION RESOURCES					
Implement Recreation Management Plan					
Rehabilitation of Existing Recreation Facilities	3-12[1]; 23-32[2]	$6,800,000		$283,082	
Enhancement New recreation facilities/Features (Dam 3 Day-Use Area and Accessible Fishing Platform)	3-7	$1,500,000		$97,418	
Manage Reservoir WSE	3-46		$2,000	$1,806	
Fund Fish Stocking (50% cost share)	3-7		$50,000	$16,236	
Fund Fish Stocking (50% cost share)	8-46		$50,000	$29,882	
Prepare Report on Recreation Resources (every 6 years)	Every 6th year, beginning 2015		$100,000	$11,216	
Interpretive Signs	3,22		$192,000	$20,177	
Attend Annual Consultation Meeting	3-46		$500	$452	
LAND MANAGEMENT					
Implement Management Plans					
Visual Resources	4-7	$10,000		$626	
Transportation System	3-46		$17,000	$18,250	
Fire Plan	3-46		$500	$452	
Spill Prevention Control and Countermeasure Plans	3-46		$500	$452	
Attend Annual Consultation Meeting	3-46		$500	$452	
Transportation System Plan Labor	3-46		$277,500	$250,620	
Transportation System Plan Equipment & Materials	3-46		$72,800	$65,748	

Attachment D-2. Cost of Environmental Measures Recommended in the Proposed Action and Resulting Reduction in Annual Energy Benefits by Project for the Big Creek Nos. 1 and 2 Project (FERC Project No. 2175).

Environmental Measures	Year(s) Implemented	Capital and One-Time Costs (2006$)	Annual Costs Including O&M (2006$)	Annualized Costs (2006$)	Reduction in Annual Energy Benefits (2006$)
CULTURAL RESOURCES					
Implement a Historic Properties Management Plan	3-7	$41,000	$4,000	$4,350	
Implement a Historic Properties Management Plan	8-46		$4,000	$2,391	
Implement Environmental Programs (Environmental, Cultural Awareness)	3-46		$1,000	$903	
Attend Annual Consultation Meeting	3-46		$500	$452	
TOTAL PROJECT 2175 COST			$1,113,800	$1,223,477	$5,683,000

[1]Years 1-10 cost = $4,500,000

[2]Years 21-30 cost = $2,300,000

ATTACHMENT D-3

FERC Project No. 2175 – Total and Annual Value

ATTACHMENT D-3

Big Creek 1 & 2 - Project 2175 Total & Annual Value

Power Present Value **$505,741 (In $2006), (In $Thousands)**
Power Levelized Value **$51,219 (In $2006), (In $Thousands)**

Year	Total Value of Power ($)	Energy Value ($)	Capacity Value ($)	Energy Price ($/MWh)	Capacity Price ($/kW-yr)	Power Escalation Factor
2006	0			49.40	69.70	2.92%
2007	0			50.41	71.13	2.05%
2008	0			51.38	72.49	1.92%
2009	51,197	40,108	11,089	52.40	73.93	1.98%
2010	52,236	40,922	11,314	53.46	75.43	2.03%
2011	53,352	41,797	11,556	54.60	77.04	2.14%
2012	54,467	42,670	11,797	55.74	78.65	2.09%
2013	55,558	43,525	12,034	56.86	80.22	2.00%
2014	56,635	44,369	12,267	57.96	81.78	1.94%
2015	57,699	45,202	12,497	59.05	83.32	1.88%
2016	58,758	46,032	12,727	60.13	84.85	1.84%
2017	59,807	46,853	12,954	61.21	86.36	1.78%
2018	60,826	47,652	13,175	62.25	87.83	1.71%
2019	61,928	48,515	13,413	63.38	89.42	1.81%
2020	63,071	49,410	13,661	64.55	91.07	1.84%
2021	64,250	50,333	13,916	65.75	92.77	1.87%
2022	65,449	51,273	14,176	66.98	94.51	1.87%
2023	66,684	52,241	14,443	68.25	96.29	1.89%
2024	67,938	53,223	14,715	69.53	98.10	1.88%
2025	69,237	54,241	14,996	70.86	99.98	1.91%
2026	70,575	55,289	15,286	72.23	101.91	1.93%
2027	71,931	56,351	15,580	73.62	103.87	1.92%
2028	73,304	57,427	15,877	75.02	105.85	1.91%
2029	74,735	58,548	16,187	76.48	107.91	1.95%
2030	76,195	59,692	16,504	77.98	110.02	1.95%
2031	77,671	60,848	16,823	79.49	112.15	1.94%
2032	79,163	62,016	17,146	81.02	114.31	1.92%
2033	80,666	63,194	17,472	82.55	116.48	1.90%
2034	82,194	64,391	17,803	84.12	118.69	1.90%
2035	83,740	65,602	18,138	85.70	120.92	1.88%
2036	85,317	66,838	18,479	87.31	123.20	1.88%
2037	86,924	68,097	18,827	88.96	125.52	1.88%
2038	88,562	69,380	19,182	90.64	127.88	1.88%
2039	90,230	70,686	19,543	92.34	130.29	1.88%
2040	91,929	72,018	19,911	94.08	132.74	1.88%
2041	93,661	73,374	20,286	95.85	135.24	1.88%
2042	95,425	74,756	20,669	97.66	137.79	1.88%
2043	97,222	76,165	21,058	99.50	140.39	1.88%
2044	99,054	77,599	21,454	101.37	143.03	1.88%
2045	100,919	79,061	21,859	103.28	145.72	1.88%
2046	102,820	80,550	22,270	105.23	148.47	1.88%
2047	104,757	82,067	22,690	107.21	151.27	1.88%
2048	106,730	83,613	23,117	109.23	154.11	1.88%
2049	108,740	85,188	23,553	111.29	157.02	1.88%
2050	110,789	86,792	23,996	113.38	159.97	1.88%
2051	112,875	88,427	24,448	115.52	162.99	1.88%
2052	115,001	90,093	24,909	117.69	166.06	1.88%

(All above are $Thousands)

Assumptions:

2007 Energy Price ($/MWh):	50.41
2007 Capacity Price ($/kW-yr):	71.13
Big Creek 1 Generation (MWh):	412,542
Big Creek 2 Generation (MWh):	352,941
Big Creek 1 Dependable Capacity (MW):	82.9
Big Creek 2 Dependable Capacity (MW):	67.1
2009 Power Value (In $Thousands):	$51,197
SCE Cost of Capital:	10.00%
License Life:	44 years
Power Escalation Factor:	GDP Index (Global Insight)

ATTACHMENT D-4

FERC Project No. 2175 – Average On-Peak and Off-Peak Generation in MWh's for Dry, Normal and Wet Years

ATTACHMENT D-4

Average On-Peak and Off-Peak Generation in MWh's for Dry, Normal and Wet Years[(1)] (FERC Project No. 2175)

Type of Year	Average Generation	On-Peak Generation	Off-Peak Generation
Dry	651,721	458,293	193,427
Normal	931,060	589,639	341,421
Wet	1,101,953	662,661	439,292

[(1)]Project 2175 receives inflow primarily from Huntington Lake with runoff varying from a dry year to a wet year. The determination of a dry, normal, or wet year is made with the annual runoff for the San Joaquin River downstream at Friant Dam. The decision of whether the year is dry, normal, or wet is done with a 30%-40%-30% division of annual runoff volume for 128 years, through 2005. The data used to provide the 31-year averages above are from 1975 through 2005.

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 1 AND 2
(FERC Project No. 2175)

EXHIBIT H(A): GENERAL INFORMATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit H(a) General Information

Exhibit H(a) describes information to be provided pursuant to 18 CFR § 16.10(a):

(1) A discussion of the plans and ability of the applicant to operate and maintain the project in a manner most likely to provide efficient and reliable electric service, including efforts and plans to:

(i) Increase capacity or generation at the project;

(ii) Coordinate the operation of the project with any upstream or downstream water resource projects; and

(iii) Coordinate the operation of the project with the applicant's or other electrical systems to minimize the cost of production.

(2) A discussion of the need of the applicant over the short and long term for the electricity generated by the project, including:

(i) The reasonable costs and reasonable availability of alternative sources of power that would be needed by the applicant or its customers, including wholesale customers, if the applicant is not granted a license for the project;

(ii) A discussion of the increase in fuel, capital, and any other costs that would be incurred by the applicant or its customers to purchase or generate power necessary to replace the output of the licensed project, if the applicant is not granted a license for the project;

(iii) The effect of each alternative source of power on:

(A) The applicant's customers, including wholesale customers;

(B) The applicant's operating and load characteristics; and

(C) The communities served or to be served, including any reallocation of costs associated with the transfer of a license from the existing licensee.

(3) The following data showing need and the reasonable cost and availability of alternative sources of power:

(i) The average annual cost of the power produced by the project, including the basis for that calculation;

(ii) The projected resources required by the applicant to meet the applicant's capacity and energy requirements over the short and long term including:

(A) Energy and capacity resources, including the contributions from the applicant's generation, purchases, and load modification measures (such as conservation, if considered as a resource), as separate components of the total resources required;

(B) A resource analysis, including a statement of system reserve margins to be maintained for energy and capacity; and

(C) If load management measures are not viewed as resources, the effects of such measures on the projected capacity and energy requirements indicated separately;

(iii) For alternative sources of power, including generation of additional power at existing facilities, restarting deactivated units, the purchase of power off-system, the construction or purchase and operation of a new power plant, and load management measures such as conservation:

(A) The total annual cost of each alternative source of power to replace project power;

(B) The basis for the determination of projected annual cost; and

(C) A discussion of the relative merits of each alternative, including the issues of the period of availability and dependability of purchased power, average life of alternatives, relative equivalent availability of generating alternatives, and relative impacts on the applicant's power system reliability and other system operating characteristics; and

(iv) The effect on the direct providers (and their immediate customers) of alternate sources of power.

(4) If an applicant uses power for its own industrial facility and related operations, the effect of obtaining or losing electricity from the project on the operation and efficiency of such facility or related operations, its workers, and the related community.

(5) If an applicant is an Indian tribe applying for a license for a project located on the tribal reservation, a statement of the need of such tribe for electricity generated by the project to foster the purposes of the reservation.

(6) A comparison of the impact on the operations and planning of the applicant's transmission system of receiving or not receiving the project license, including:

(i) An analysis of the effects of any resulting redistribution of power flows on line loading (with respect to applicable thermal, voltage, or stability limits), line losses, and necessary new construction of transmission facilities or upgrading of existing facilities, together with the cost impact of these effects;

(ii) An analysis of the advantages that the applicant's transmission system would provide in the distribution of the project's power; and

(iii) Detailed single-line diagrams, including existing system facilities identified by name and circuit number, that show system transmission elements in relation to the project and other principal interconnected system elements. Power flow and loss data that represent system operating conditions may be appended if applicants believe such data would be useful to show that the operating impacts described would be beneficial.

(7) If the applicant has plans to modify existing project facilities or operations, a statement of the need for, or usefulness of, the modifications, including at least a reconnaissance-level study of the effect and projected costs of the proposed plans and any alternate plans, which in conjunction with other developments in the area would conform with a comprehensive plan for improving or developing the waterway and for other beneficial public uses as defined in section 10(a)(1) of the Federal Power Act.

(8) If the applicant has no plans to modify existing project facilities or operations, at least a reconnaissance-level study to show that the project facilities or operations in conjunction with other developments in the area would conform with a comprehensive plan for improving or developing the waterway and for other beneficial public uses as defined in section 10(a)(1) of the Federal Power Act.

(9) A statement describing the applicant's financial and personnel resources to meet its obligations under a new license, including specific information to demonstrate that the applicant's personnel are adequate in number and training to operate and maintain the project in accordance with the provisions of the license.

(10) If an applicant proposes to expand the project to encompass additional lands, a statement that the applicant has notified, by certified mail, property owners on the additional lands to be encompassed by the project and governmental agencies and subdivisions likely to be interested in or affected by the proposed expansion.

(11) The applicant's electricity consumption efficiency improvement program, as defined under section 10(a)(2)(C) of the Federal Power Act, including:

(i) A statement of the applicant's record of encouraging or assisting its customers to conserve electricity and a description of its plans and capabilities for promoting electricity conservation by its customers; and

(ii) A statement describing the compliance of the applicant's energy conservation programs with any applicable regulatory requirements.

(12) The names and mailing addresses of every Indian tribe with land on which any part of the proposed project would be located or which the applicant reasonably believes would otherwise be affected by the proposed project.

(1) Efficient and Reliable Operation and Maintenance of Project

(i) Increased Capacity or Generation at the Project

Southern California Edison Company (SCE) currently has no plans to further increase capacity or generation at the Project.

(ii) Coordinate the Operation of the Project with Any Upstream or Downstream Water Resource Projects

Project Operations

Operation of SCE's seven FERC-Licensed Projects in the Big Creek System (BCS) is managed from a watershed-wide perspective and on an individual project-by-project basis. The BCS consists of six major reservoirs (Thomas A. Edison, Florence, Huntington, Redinger, Shaver, and Mammoth Pool,) and nine powerhouses (Portal; Eastwood; Mammoth Pool; and Big Creek Powerhouse Nos. 1, 2, 2A, 3, 4, and 8). Figure B-1 of Exhibit B presents a schematic diagram of the seven FERC licensed Projects and associated reservoirs, water conveyance tunnels and powerhouses in the BCS. The operation of the BCS and the individual Projects is dependent on natural run-off and the operation of other components in the system, storage requirements of the Mammoth Pool Operating Agreement, the amount of generation required for SCE's customers, and the dispatching of energy in accordance with the California Independent System Operator requirements.

SCE operates the four Big Creek ALP Projects within the BCS in accordance with FERC license conditions, which includes MIF release requirements from diversions and impoundments.

The management of water through the BCS and specifically the four Big Creek ALP Projects routes water between Projects in a manner that best meets the operational constraints that are imposed either by contractual operating agreements (i.e., licenses, permits, etc.) or by physical limitations of the Project infrastructure. The BCS is subject to several operating constraints including the following: (1) available water supply; (2) electrical system requirements; (3) both planned and unplanned maintenance outages; (4) storage limits (including both recreation minimums and year-end carryover maximums); (5) both minimum and maximum release limits (from storage); (6) various provisions contained in water rights agreements; and (7) California Independent System Operator requirements.

Water Rights and Contractual Obligations

Each of SCE's Big Creek Hydroelectric Projects either has separate water rights or shares one or more water rights with other projects for the diversion, use, and storage of water. The majority of the water rights are for non-consumptive uses associated with the generation of power. A few locations, such as SCE's administrative offices and company housing near Big Creek No. 1 Powerhouse have minor consumptive water rights. SCE does not hold water rights for the consumptive use of water by any party other than SCE, nor does SCE sell any water rights associated with the hydropower projects to other parties.

SCE's water rights were obtained pursuant to state law and a majority of the water rights are documented by licenses and permits issued to SCE, or its predecessors, by the State Water Resources Control Board (State Water Board). Additional water rights were obtained through appropriation of water prior to the implementation of the Water Commission Act of 1914, and by prescriptive use against other parties. SCE also holds other water rights as a riparian land owner, which authorizes SCE to divert and use water on land owned by SCE.

The water rights agreements contain stipulations that stem from the senior status of certain downstream water rights holders. Generally, any water right holder with senior rights began diverting water for consumptive purposes prior to SCE or its predecessors. To protect the rights of the downstream water rights holders, SCE entered into agreements that restrict the use of water within the BCS to non-consumptive purposes, i.e., hydroelectric generation. Certain agreements limit the length of time and amount of water that SCE can store in its Project reservoirs. In a few instances, SCE's non-consumptive water use is a senior water right, and other water users hold junior water rights.

SCE operates its reservoirs consistent with the Mammoth Pool Operating Agreement (MPOA), which specifies cumulative reservoir storage constraints based on the computed natural run-off for the water year at Friant Dam. The MPOA between SCE and the U.S. Bureau of Reclamation (Bureau) specifies water storage and release requirements for the BCS reservoirs, which are upstream of Friant Dam (Millerton Reservoir) and the associated Central Valley Project water distribution system operated by the Bureau on behalf of the downstream irrigators. Millerton Reservoir is a major irrigation storage facility serving the central San Joaquin Valley agricultural community. Meetings between SCE, the Bureau, and the downstream irrigators are held following the March 1 run-off forecast each year, and periodically as needed, to coordinate and optimize hydropower production consistent with irrigation needs of the downstream agricultural users holding senior water rights and emergency flood control operations of Millerton Reservoir. The MPOA includes constraints on the annual and seasonal timing and volume of releases from SCE's reservoirs, maximum year-end storage allowed, and minimum seasonal flow from Dam No. 7 (release and diversion).

BCS Water Management

A key component of the annual water management plan for the BCS is the development of an annual run-off forecast. The annual run-off forecast is developed based on snow pack and precipitation data collected in the vicinity of the Project. This information is used along with assumptions about future median precipitation and air temperatures to produce a run-off forecast through the end of the water year (September 30). The forecast includes an estimate of both the timing and the quantity of water that will enter Project reservoirs during that run-off season. Snow pack and precipitation data are shared with the California Department of Water Resources (DWR) and the Bureau, who use it to develop individual forecasts of run-off volumes and declare water year types (critical, dry, below normal, above normal, or wet). The run-off forecast is a valuable tool for planning and ensuring compliance with the constraints of the MPOA (described above) and for planning purposes. A majority of the MPOA and other constraints are based on actual run-off volumes. The forecast also is used for directing future operational plans for: (1) instream flow release requirements; (2) reservoir recreational storage requirements; and (3) hydroelectric generation operations for the entire BCS.

The operation of the BCS is similar in all water year types in that water diverted from Project reservoirs and diversions is utilized to generate power. There are subtle differences, however, in the way that the Project is operated during different water year types and during different conditions of state energy requirements.

Some of the BCS reservoirs generally spill in wet and above normal water years and are filled to maximum capacity when spill ceases. When the BCS reservoirs stop spilling, SCE is able to manage the system with available inflows and begin managing the water to meet electric supply requirements by providing both base load and peak cycling energy. In the upper basin area, water from the upper South Fork San Joaquin River drainage is stored in Florence Lake and water from Mono Creek drainage is stored in Lake Thomas A. Edison. Water is diverted from these two lakes and various other small backcountry diversions into Huntington Lake via the Ward Tunnel and the Mono-Bear Siphon. The volumes of water that can pass through Ward Tunnel and the siphon are limited by the physical size and layout of these conduits. Water deliveries to Huntington Lake are prioritized as follows: first priority is given to water from Florence Lake; second priority is given to water from Bear Diversion and Lake Thomas A. Edison; and third priority is given to water diverted from the small diversions at Camp 61 Creek, Camp 62 Creek, Chinquapin Creek and Bolsillo Creek. The water delivered to Huntington Lake may also pass through Portal Powerhouse at the exit of the Ward Tunnel depending upon the amount of water being transported.

BCS Power Generation

The BCS has three interlinked water chains or pathways through which water may be transported and used to produce power. The three water chains are:

- Huntington Water Chain: This chain consists of Portal Powerhouse, Powerhouse No. 1, Powerhouse No. 2, Powerhouse No. 8, Powerhouse No.3, and Powerhouse No. 4.
- Shaver Water Chain: This chain consists of Portal Powerhouse, Eastwood Power Station, Powerhouse No. 2A, Powerhouse No. 8, Powerhouse No. 3, and Powerhouse No. 4.
- Mammoth Water Chain: This chain consists of Mammoth Pool Powerhouse, Powerhouse No. 3, and Powerhouse No. 4.

After passing through or bypassing the Portal Powerhouse, water entering Huntington Lake is directed to either the Huntington Chain, or the Shaver Chain. If the generation from the powerhouses of either chain is increased or decreased proportionally, the changes in load will have no effect on the MIF, or total levels of the storage reservoirs and forebays within the BCS. Changes in total loading conditions of the two chains can, however, affect Florence Lake and Lake Thomas A. Edison and can affect the amount of water leaving the project at Powerhouse No. 4. If generation from the powerhouses of either chain is changed disproportionately, the levels of Huntington Lake, Shaver Lake, and Redinger Lake can be increased or decreased.

Water from Big Creek Powerhouse Nos. 1 and 2 in the Huntington Chain joins water from the Shaver Chain, which has already passed through Eastwood Power Station and Big Creek Powerhouse No. 2A, at the Big Creek Powerhouse No. 2 and 2A Tailrace (Dam 5). Water from these two chains is then diverted through Big Creek Powerhouse No. 8, after which it joins the waters of the San Joaquin River coming from the Mammoth Chain at the Big Creek No. 8 Tailrace (Dam 6 Impoundment). Water from all three chains then continues through Big Creek Powerhouse Nos. 3 and 4.

Waters from the Middle Fork and North Fork San Joaquin River (SJR) drainages, and the South Fork SJR flows not diverted at Florence Lake, Lake Thomas A. Edison, Bear Creek Forebay, and the small backcountry diversions, are collected in Mammoth Pool Reservoir and become part of the Mammoth Chain. Mammoth Pool Powerhouse is usually run at maximum during the high flow or run-off period to prevent or delay spill at Mammoth Pool Reservoir.

For the most part, Portal Powerhouse, Eastwood Power Station, and Big Creek No. 4 Powerhouse operate independently of the other powerhouses in the BCS. Portal Powerhouse opportunistically uses water passing through the Ward Tunnel for power generation, but only operates efficiently at moderate flows through Ward Tunnel. Ward Tunnel flows outside the efficient flow range of Portal Powerhouse bypass Portal Powerhouse through the Howell Bunger (HB) valve into Huntington Lake. Eastwood Power Station generation normally occurs during the peak demand period of the day, unless water is being moved continuously from Huntington Lake to Shaver Lake to avoid spill at Huntington Lake or to increase storage at Shaver Lake for use during peak periods. Maintaining storage (water surface levels) to maintain recreational needs at Huntington Lake and above pump-back minimum water surface level in Shaver Lake are important considerations when planning operations at Eastwood Power Station. Big Creek Powerhouse No. 4 is the last power generation opportunity in the Big Creek System and therefore adjustments in the operation of the Powerhouse No. 4 will not affect other upstream powerhouses in the BCS.

Generally, the three water chains of the BCS are operated around the clock in the spring run-off period, except in dry water years. Operational flexibility is limited during normal run-off because the amount of water run-off available exceeds the combined generation and storage capacity of the project, resulting in water flowing over spillways or “spill”.

After the end of the spill period, daily unit plant load schedules are established to maximize hydro resources during system peak load periods. When spring run-off is finished, if a powerhouse does not need to operate for water management, it is run preferentially during on-peak hours. Due to the nature of the energy market and SCE's resources, it is generally beneficial for the Big Creek Projects to provide power during on-peak hours, once the spring run-off has finished. Since the BCS powerhouses discharge to reservoirs or forebays, the peaking operations generally do not cause varying flows in bypass reaches. Energy load changes on these power generation chains will not affect the water surface elevation (WSE) or instream flows, as long as adjustments are made to match reservoir inflows and outflows. A proprietary computer model used for predicting inflow is also used to plan monthly flow of water through the Project to meet the operating constraints on the system while maximizing generation during the peak load periods. In addition, computer programming of load schedules to use the most efficient units first, further enhances these operating activities and improves system integrity and efficiency. These activities can ensure the efficient use and availability of hydroelectric generation resources from these reservoir storage plants.

Market constraints and pricing, as well as transmission constraints and weather, will affect generation and operations at the Big Creek Projects. Often during the spring run-off season there is a financial disadvantage for SCE to generate energy even though to avoid generation would cause spill to occur. A simplified description of the California energy market describes the Independent System Operator (ISO) as having the role of balancing energy demand and supply in the state. The ISO takes the energy demand forecast, the transmission system constraints, and the energy that is bid into the day-ahead market to determine the acceptable energy supply. The ISO then adjusts the supply load on a real-time basis to account for changing conditions. If the ISO believes that there is a surplus of energy available beyond that necessary to supply the grid, prices in the California energy market for additional energy could be negative. This situation would require SCE to pay for contributing additional energy.

Water Management of Big Creek Nos. 1 and 2 Project (FERC Project No. 2175)

The Big Creek Nos. 1 and 2 powerhouses, located on Big Creek, can be operated locally from the control rooms at Powerhouse No. 1 or Powerhouse No. 2, or remotely from Big Creek Powerhouse No. 3 (FERC Project No. 120), which serves as the main control center for the entire BCS. The water used by the Project is stored in Huntington Lake, which includes local run-off and water conveyed through Ward Tunnel from Florence Lake (FERC License No. 67), Lake Thomas A. Edison (FERC

No. 2086), and from various small and intermediate size stream diversions. Powerhouse No. 1 utilizes water from Huntington Lake and discharges into the Dam 4 impoundment on Big Creek. Powerhouse No. 2 receives water from the Dam 4 impoundment and discharges to the Dam 5 impoundment on Big Creek.

The Big Creek Nos. 1 and 2 Project operates in conjunction with the rest of the BCS in a parallel and stair step sequence of water chains. Big Creek Powerhouses No. 1 and 2 represent the second and third generating opportunities in the Huntington Water Chain, respectively. The flow of water through the Powerhouse Nos. 1 and 2 Project is dependent on natural run-off during periods of snowmelt and wet weather and the operation of reservoirs in the BCS that are located at higher elevations within the drainage.

The operation of the Powerhouse Nos. 1 and 2 Project is similar in all water year types in that water diverted into the Project from remote impoundments and diversions is utilized to generate power when the water is available. In wet water years, the Project runs at full capacity beginning in mid April to May until the end of peak run-off, which typically occurs in late July and SCE gains control of inflows. Then, SCE will manage powerhouse operations to meet base load requirements and/or peak cycling energy needs. Project generation is greater during wet water years and spills can occur at Dam 4.

In above normal water years, the Project is generally run at full capacity beginning in May until the end of peak run-off, which typically occurs in July. Some of the BCS reservoirs generally spill in above normal water years and are filled to maximum capacity until spill ceases. At that time, SCE gains control of inflows and begins managing the water to meet grid requirements by providing both base load and peak cycling energy.

During dry water years, the Project may run at full capacity for a short duration in May and June. In some dry water years, the Project does not run at full capacity in order to fill the reservoirs to maximum capacity. Project generation is lower in dry water years and very little water, other than required dam seepage and MIF releases, bypasses the powerhouses.

Under the Proposed Action, water management would remain generally the same as existing operations. However, under the Proposed Action, MIF's would be released from Dam 4, Balsam Creek Diversion, and Ely Creek Diversion.

(iii) Coordinate the Operation of the Project with Other Electrical Systems to Minimize the Cost of Production

SCE optimizes the use of the Project to provide maximum generation during run-off and peak demand periods. The entire set of SCE generation facilities is coordinated through the SCE Energy Control Center to maximize generation while minimizing economic and environmental costs. SCE bids power from its retained generation facilities into markets governed by the Independent System Operator (ISO). Thus, electrical generation from the BCS and the four BC ALP Projects is coordinated with other generation throughout California.

(2) Need for the Project

The need for the Project is twofold as: (1) SCE needs the capacity of the Project to supply its customers; and (2) the value of the energy produced by the Project is greater than the costs associated with producing this energy. Continued operation of the Project will reduce the need for SCE to purchase replacement energy and capacity which would be significantly more expensive than the production costs associated with the Project. In addition, the Project contributes to the fuel diversity of SCE's energy supply and is a significant hedge against the potential impacts of the volatile natural gas market.

The environmental value of the Project mainly consists of using a non-polluting renewable fuel resource to displace other forms of generation such as gas-fired energy that creates air pollution as well as using non-renewable resources. The Project is, however, too large to be included as an Eligible Renewable form of energy, based on accounting regulations in California, and thus does not assist SCE in meeting the goals of California's Renewable Portfolio Standard (CA Senate Bill 1078).

(i) Costs and Availability of Alternative Sources of Power

SCE is presently unable to supply energy to its entire customer load from SCE owned generation resources for all hours.

Load management is not currently an option to replace this Project, as it might be able to supply capacity but cannot supply the amount of energy that these large hydroelectric facilities produce. Energy efficiency is not a viable option in place of these facilities, because SCE is already planning on utilizing all of the available cost-effective energy efficiency programs. SCE was encouraged to, and eventually did, divest of all of its natural gas generation facilities when the California market deregulation occurred in early 1998, therefore SCE does not have any deactivated or retired plants that can be restarted to replace this capacity and energy.

SCE must therefore purchase its unmet capacity and energy requirements from the existing market. Since SCE does not currently have the necessary resources nor do we plan to develop sufficient resources to meet all our energy obligations, SCE would likely purchase "net short" customer load requirements from the market, either through bilateral transactions or through spot market purchases. It is estimated that the cost of replacement power would be approximately $51.2 million per year in 2006($) and this cost would escalate in future years. This energy is expected to be readily available.

(ii) Increase in Fuel, Capital, and Other Costs

If this Project were not licensed, the replacement power could not be generated by SCE, but would be purchased from the market as discussed above. SCE would incur the costs associated with purchasing the replacement power for its customers. If firm energy contracts are purchased, the expected cost of those contracts is the same as above at approximately $51.2 million per year in 2006($) and escalating thereafter.

If contracts are structured as tolling arrangements, where SCE provides the natural gas for a generator, SCE may be required to purchase the natural gas necessary for the contracted generator to produce this energy. It is estimated that the cost to purchase the gas and replace the energy provided by this Project would total $58.2 million. This assumes an average of 10,000 Btu/kWh heat rate for replacement energy and the gas price is based on a five-day average of NYMEX natural gas forward prices (as of December 20, 2006) plus a Southern California Gas Company transportation charge. Costs associated with this Project not obtaining a new license would include the cost of obtaining contracts to replace the energy and capacity provided by this Project. There may also be some additional costs in purchasing ancillary services (such as spinning reserve) if these hydro resources cannot be used for those purposes. No estimate of those costs has been provided in this filing.

(iii) Effect of Alternative Sources of Power

The Project provides a stabilizing low-cost base of generation with high reliability and, with a dependable operating capacity of 150.0 MW (82.9 MW and 67.1 MW for Big Creek 1 and 2, respectively), accounts for approximately 15% of the total hydroelectric capacity for SCE's Northern Hydroelectric Division. If a new license is not granted, it will have a significant impact on SCE's total hydroelectric energy capability.

(A) The Project provides lower cost energy to SCE's customers than the cost of replacement energy. This cost savings is not specifically assigned to any one class of customers, including wholesale customers. System generation serves all customers through a diverse transmission system and with a generation mix based on many different resources such as gas, coal, nuclear, hydroelectric, and purchases from other utilities or non-utility power producers. If the resources mix shifts from low cost resources such as hydroelectric generation to higher cost resources such as gas-fired generation, the cost to all customers will increase. Without a new Project license, some of this resource shifting would occur.

(B) The generation and load projections for 2010 show that SCE hydroelectric generation will represent 6% of the supply of Utility-Retained Generation, which will enable SCE to meet approximately 5% of its load requirements. See Exhibit H(a)(3)(ii) for more detail.

(C) The Project is located near the communities of Huntington Lake and Big Creek. However, electrical service to these communities relies more on the local power grid in the area than the generation produced by the Project. The service area for power generated by the Project is predominantly the Los Angeles Basin and a portion of the central San Joaquin Valley. SCE would need to purchase replacement power from alternative power sources if a new license is not granted. Replacement power would need to be purchased from the power grid market, which would increase energy costs to SCE customers.

The costs associated with transfer of the license would be the same as the severance value described in Exhibit D(2)(iii).

(3) Need, Cost, and Availability of Alternative Sources of Power

The power produced by the Project cannot be replaced by an alternative source at a lower cost. Following the divestiture of the SCE gas-fired plants, it became necessary for SCE to purchase power during on-peak periods. Changing to an alternative source of power would increase purchased power at a higher cost than continuing operation of the Project.

(i) Average Annual Cost of Power Produced by the Project

The Project has an installed capacity of 154.85 MW and the dependable operating capacity is 150.0 MW. Table H(a)-1 presents the Project's recorded annual generation output for 15 years (1991-2005). The lowest year of generation production in the 15-year period occurred in 2001 at 481,815 MWh and the highest occurred in 1997 at 1,121,742 MWh. The average production for the 15-year period was 765,483 MWh.

This Project Net Investment as of December 31, 2005 was $39,594,897 and the direct O&M expenses for this Project are $7,107,462, which is an annualized value for the life of the license. Additional Project operating expenses and capital costs are discussed in Section D(4).

(ii) The Project Resources Required by SCE to Meet Capacity and Energy Requirements

(A) *Energy & Capacity Resources As Separate Components Of Total Resources Required*

SCE currently does not own or operate enough generation to meet all of its future projected load and energy obligations. Table H(a)-2 projects the amount of energy expected from the Utility Retained Generation (URG) in the years 2010 and 2015. This table also gives an estimate of how much of SCE's future energy needs, assuming that the Direct Access load in the SCE service territory will remain constant beyond 2006, will be met by the URG resources. Demand-side management (i.e., conservation and energy efficiency) expectations are built into the table's Load forecast.

Table H(a)-1. Average Project Generation Output Between 1991-2005.

Year	Production in MWH (Transmitted)		
	PH No. 1	PH No. 2	Project Total
1991	284,011	241,640	525,651
1992	268,552	240,900	509,452
1993	523,600	453,101	976,701
1994	294,351	260,822	555,173
1995	549,019	481,493	1,030,512
1996	539,253	455,497	994,750
1997	628,022	493,720	1,121,742
1998	571,090	445,497	1,016,587
1999	390,999	337,212	728,211
2000	417,714	352,943	770,657
2001	254,827	226,988	481,815
2002	270,792	283,077	553,870
2003	375,743	318,385	694,128
2004	343,750	308,983	652,733
2005	476,404	393,857	870,261
15-Year Average:	**412,542**	**352,941**	**765,483**

Table H(a)-2: Expected Utility Retained Generation (URG) in 2010 and 2015.

Generation Source	2010 GWH	2010 % Supply	2010 % Load	2015 GWH	2015 % Supply	2015 % Load
Utility-controlled Resources						
Nuclear	15,527	20%	18%	16,902	29%	18%
Hydro	4,775	6%	5%	4,687	8%	5%
Fossil	10,101	13%	11%	10,816	19%	11%
Must-take DWR	19,946	26%	23%	0	0%	0%
Qualifying Facility Contracts	23,581	31%	27%	23,208	40%	24%
Existing Renewable Contracts	2,438	3%	3%	2,434	4%	3%
Total URG*	76,368	100%	87%	58,047	100%	60%

Source: 2005 IEPR Alternative Case, Public Version of Form S-2, filed in CEC by SCE on April 1, 2005.
* URG less interutility contracts (i.e., Hoover, etc.)

(B) *Resource Analysis and System Reserve Margins*

The California Independent System Operator (Cal ISO) is responsible for maintaining statewide system operating reserve margins that meet the WECC required operating reserve margin requirements. The Cal ISO attempts to maintain an operating reserve of about 7%, with 3.5% as spinning reserve and 3.5% as non-spinning reserve. For a breakdown of utility-owned generation, see the above table. In addition to operating reserves, SCE will be required to provide the CAISO with documentation related to meeting the state Resource Adequacy or planning reserve margins. This Project can, and will, count towards meeting these planning reserve requirements.

(C) *Effects of Efficiency and Load Management Plans*

SCE has developed comprehensive efficiency and load reduction plans that will encourage electrical customers to decrease their load, especially during peak periods. Reference Exhibit H(a)(11).

SCE is committed to the continued development of cost effective energy efficiency and load management programs that will help the utility provide uninterrupted service to its customers. The 2005 SCE energy efficiency programs achieved over 1,372,000 MWh of net annualized energy savings and a net demand reduction of 265.2 MW.

(iii) Cost and Merits of Project Alternatives

As previously discussed in Exhibit H(a)(2)(i), SCE has very limited options regarding alternative sources of power. At the current time, the only feasible alternative is receiving energy from the wholesale energy market.

(A) *Annual Costs for Alternative Sources of Power*

The cost of replacement power in 2009 is $51.2 million per year (nominal dollars). See discussion above in Exhibit H(a)(2)(i).

(B) *Basis for Determination of Projected Annual Cost*

The projected annual cost of alternative power is determined by estimating the cost of replacing the power provided by this Project at SCE's forecast of its avoided cost of energy and capacity. As previously noted the number of MWh's needed for replacement was derived from a 15-year annual historical average. This average was then multiplied by the avoided cost of energy and capacity as forecasted by SCE in its 2006 General Rate Case (GRC) filing. Since this forecast is not available past 2008, it is assumed that the avoided cost will increase at a level consistent with other escalation assumptions as discussed above. See also Exhibit H(a)(3)(i).

(C) *Relative Merits of Each Alternative*

Forward purchases of energy are likely to be characterized by market forces. Their availability is subject to the terms and conditions specified in contracts as well as forces at work in the marketplace. The Project's availability is limited by the amount of water available to be diverted and/or stored upstream of the Project, which is governed by the precipitation available in any given year.

(iv) The Effect on the Direct Providers of Alternative Sources of Energy

Relicensing of the Project would have a negative effect on suppliers of alternative sources of power. It would reduce the amount of purchases made by SCE and increase the total supply of generation in the market, thus likely causing power prices to decrease.

In addition, SCE has long and short-term contracts with both public and private utilities. Generally, when utilities have different peak seasons they can exchange energy and capacity on a seasonal basis for each other's benefit. There would be minor effect to the other utilities from utilizing alternate sources of power as the overall average cost for exchange energy would increase which would create less opportunity to make exchanges.

(4) Effect on Industrial Facilities

The Project does not connect or otherwise provide direct electricity to any of SCE's facilities.

(5) Tribal Need for the Project on a Reservation

Applicant is not an Indian tribe nor is the Project on a Tribal reservation.

(6) Comparison of Impact on Operations and Planning of Transmission System With and Without License Renewal

(i) Transmission and distribution lines and the associated equipment that deliver power from FERC Project No. 120 are part of SCE's transmission and distribution system and are not included in the FERC license for the Project. The Project and other hydroelectric plants in the area dependably deliver a collective total of 1,000 MW of power to serve approximately 1.2 million customers in the San Joaquin Valley and the Los Angeles basin. Removal of the 181 MW of Project generation would result in SCE's inability to adequately serve its customers in the San Joaquin Valley and Los Angeles basin areas during high load conditions. Insufficient transmission capability south of the San Joaquin Valley, and, in particular, south of the Rector Substation limits SCE's ability to import power into the region. Additional capacity would be necessary to import power to serve the San Joaquin Valley. As a result, significant transmission upgrades, in the form of new 230 kV or 500 kV transmission lines, would be necessary if the Project generation is unavailable. The new transmission lines would need to be connected to the Magunden Substation located 65 miles south of Rector and possibly the Vincent or Pardee Substations located an additional 95 miles south of Magunden, if power were imported from southern California or the southwest. Until such time that the new transmission facilities are constructed, significant involuntary load interruption in violation of established Western Electric Coordinating Council Planning Criteria would be needed during normal and outage conditions when loads are high to ensure remaining transmission facilities do not load beyond the maximum allowable limits.

(ii) SCE's existing transmission system distributes the Project's power and utilizes the Project's power to serve local substation load. No other distribution or transmission system is currently available to transmit Project power.

(iii) Customer load demand within the San Joaquin Valley is served by utilizing local area generation resources as well as importing power from the south. The local area generation includes Big Creek Hydro generation resources that collectively add up to over 1,000 MW. Big Creek No. 3 Project generation resources account for approximately 181 MW of this total generation. Power from the south is imported into the San Joaquin Valley through existing 220 kV transmission facilities that originate at the SCE Vincent (Los Angeles County Acton area) and SCE Pardee (Los Angeles County Santa Clarita area) Substations. These transmission lines connect together at the SCE Magunden Substation (Kern County

Bakersfield area). From the Magunden Substation, four 220 kV transmission lines run north towards the Big Creek Hydro Facilities connecting three A-Stations (Springville, Rector, and Vestal 220 kV Substation) along the way that serve the local San Joaquin Valley loads. Collectively, these four lines are limited in capacity to approximately 1,000 MW with all facilities in service and 500 to 800 MW (depending on system conditions) under loss of a single transmission line. A single-line diagram of the Big Creek System is shown in Attachment H(a)-1.

(7) Plans for Modifications

SCE has no plans at this time to modify existing Project facilities or operations to increase generation capacity.

(8) Conformance with Comprehensive Plans

The Project facilities and operations, including mitigation measures proposed in Exhibit E, are best adapted to a comprehensive plan for the San Joaquin River based on a balance between environmental protection, water supply, recreation, and the commerce and utilization of a low-cost, non-polluting source of energy. The Project, as proposed in this Application for New License, takes into account all existing and potential uses of the South Fork of the San Joaquin River, including recreation, economically viable hydroelectric generation, energy conservation in the context of the national interests in non-polluting and non-fossil fuel alternatives, public safety, and various aspects of environmental protection, including the prevention of significant detrimental impacts to fish and wildlife resources.

In addition, identification and review of the potentially relevant comprehensive plans indicate that relicensing of the Project will not conflict with the goals or objectives of any such plans. Accordingly, the Project adopts measures to ensure public safety, protect the environment, provide recreation opportunities, and operate for maximum efficiency and reliability, and thus provide the best possible overall mix of benefits.

(9) Financial and Personnel Resources

SCE's source and extent of financing and annual revenues are sufficient to meet the continuing operation and maintenance needs of the Project. For specific financial information, refer to FERC Form No. 1 which is provided to the Commission annually.

SCE has personnel resources necessary to meet license obligations for the Project. A variety of training resources and approaches are used, including classroom training, workshops, textbooks, on-the-job training, and safety training to all personnel. Safety training is conducted through a combination of regularly scheduled monthly meetings, crew meetings, on-the-job training, and special programs as needed. The training covers SCE's Occupational Safety, Health, and Fire Prevention rules and hazardous materials handling, as well as, programs mandated by governmental agencies such as the California Occupational Safety and Health Division, as well as training related to compliance with Commission license articles, and environmental and cultural protection programs.

Job knowledge and skills training programs are available for management, supervisor/administrative, clerical, and craft employees with apprenticeship training programs established for selected job classifications. Individual training needs are evaluated continually and employees are subsequently scheduled into existing programs offered within SCE or into appropriate outside training programs.

Employees are also encouraged to further their education through the educational assistance program which provides financial assistance for eligible employees who participate in job related courses, correspondence programs, and degree and/or certificate programs sponsored by accredited institutions.

(10) Notification of Expansion to Property Owners

SCE is not proposing to expand the Project to additional lands.

(11) Efficiency Improvement Program

(i) SCE is actively engaged in energy efficiency, conservation and environmentally beneficial programs. Successful program offerings include customer incentives, information and education, surveys and cooperative efforts with third-party contractors and other utilities. Some of the energy efficiency programs include:

Incentives

SCE's incentive programs include non-residential Value and Energy Stream Mapping (VESM) Advantage Plus Program, Small Nonresidential Hard-to-Reach, Express Efficiency, Standard Performance Contract, Savings by Design and the Upstream HVAC Motors Rebates Program.

SCE's residential incentive programs include Single-family Energy Efficiency Rebates, Multifamily Energy Efficiency Rebates and Appliance Recycling Programs.

Information Programs

SCE's non-residential information programs include Non-residential Energy Surveys, Building Operative Certification, and Pump Test & Hydraulic Services. SCE's Home Energy Efficiency Surveys target residential customers. Other information is disseminated to customers at Customer Technology Applications Center technology center, located in

Irwindale, California, and SCE's Agricultural Technology Applications Center located in Tulare, California.

Additional information regarding energy efficiency and conservation programs is provided on SCE's website: http://sce.com

(ii) Regulatory compliance and reporting of SCE's energy efficiency programs is tracked through collection, reporting, and verification of information on the programs' performance. The results of the performance of the programs are filed annually with the California Public Utilities Commission pursuant to Protocols and Procedures for the Verification of costs, benefits and shareholder Earnings from Demand-side Management Programs revised June 1999.

(12) Indian Tribes Affected by Project

The Project does not cross any Native American lands; therefore, no lands owned or reserved on behalf of any Native American tribe or tribal organization are affected by the Project.

SCE conducted consultations with the Native American organizations listed below. This contact list was provided by the Sierra National Forest.

Big Sandy Rancheria*
P.O. Box 337
Auberry, CA 93602

Cold Springs Rancheria*
P.O. Box 209
Tollhouse, CA 93667

North Fork Rancheria*
P.O. Box 929
North Fork, CA 93643

Dunlap Band of Mono Indians
P.O. Box 344
Dunlap, CA 93621

Picayune Rancheria*
46575 Road 417
Coarsegold, CA 93614

Table Mountain Rancheria*
23736 Sky Harbor Road
P.O. Box 410
Friant, CA 93626

Mono Nation
P.O. Box 800
North Fork, CA 93643

North Fork Mono Tribe
13396 Tollhouse Road
Clovis, CA 93611

Sierra Nevada Native American Coalition
P.O. Box 125
Dunlap, CA 93621

Bishop Tribal Council
50 Tu Su Lane
Bishop, CA 93514

Sierra Mono Museum
33103 Road 288
North Fork, CA 93643

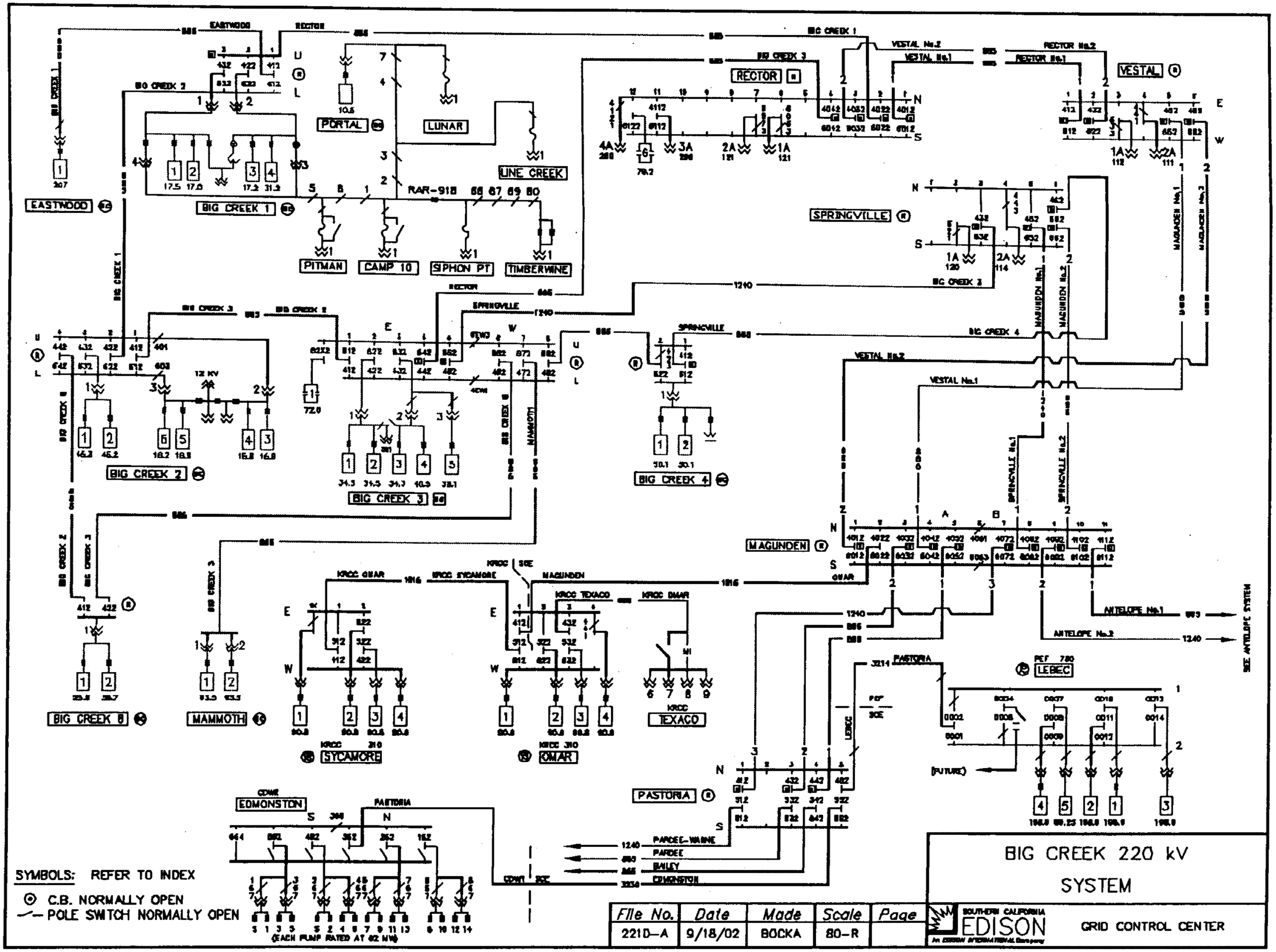
Native Earth Foundation
34329 Shaver Springs Road
Auberry, CA 93602

Michahai Wuksachi
1174 Rockhaven Ct
Salinas, CA 93906

*Federally recognized tribal organization

ATTACHMENT H(a)-1

Single Line Diagram


EASTWOOD
PORTAL
LUNAR
LINE CREEK
BIG CREEK 1
PITMAN
CAMP 10
SIPHON PT
TIMBERWINE
RAR-918
RECTOR
VESTAL
SPRINGVILLE
BIG CREEK 2
BIG CREEK 3
BIG CREEK 4
BIG CREEK 8
MAMMOTH
MAGUNDEN
SYCAMORE
OMAR
TEXACO
LEBEC
PASTORIA
EDMONSTON
ANTELOPE No.1
ANTELOPE No.2
SEE ANTELOPE SYSTEM
(FUTURE)
(EACH PUMP RATED AT 82 MW)
SYMBOLS: REFER TO INDEX
C.B. NORMALLY OPEN
POLE SWITCH NORMALLY OPEN
BIG CREEK 220 kV
SYSTEM
File No. 221D-A
Date 9/18/02
Made BOCKA
Scale 80-R
Page
SOUTHERN CALIFORNIA EDISON
GRID CONTROL CENTER

SOUTHERN CALIFORNIA EDISON COMPANY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR NEW LICENSE

BIG CREEK NOS. 1 AND 2
(FERC Project No. 2175)

EXHIBIT H(B) GENERAL INFORMATION

CONTAINS PUBLIC INFORMATION

FEBRUARY 2007

Exhibit H(b) General Information

Exhibit H(b) is information to be provided by an applicant who is an existing licensee. An existing licensee that applies for a new license must provide the information as specified in 18 CFR § 16.10(b):

(1) The information specified in H(a).

(2) A statement of measures taken or planned by the licensee to ensure safe management, operation, and maintenance of the project, including:

(i) A description of existing and planned operation of the project during flood conditions;

(ii) A discussion of any warning devices used to ensure downstream public safety;

(iii) A discussion of any proposed changes to the operation of the project or downstream development that might affect the existing Emergency Action Plan, as described in subpart C of part 12 of this chapter, on file with the Commission;

(iv) A description of existing and planned monitoring devices to detect structural movement or stress, seepage, uplift, equipment failure, or water conduit failure, including a description of the maintenance and monitoring programs used or planned in conjunction with the devices; and

(v) A discussion of the project's employee safety and public safety record, including the number of lost-time accidents involving employees and the record of injury or death to the public within the project boundary.

(3) A description of the current operation of the project, including any constraints that might affect the manner in which the project is operated.

(4) A discussion of the history of the project and record of programs to upgrade the operation and maintenance of the project.

(5) A summary of any generation lost at the project over the last five years because of unscheduled outages, including the cause, duration, and corrective action taken.

(6) A discussion of the licensee's record of compliance with the terms and conditions of the existing license, including a list of all incidents of noncompliance, their disposition, and any documentation relating to each incident.

(7) A discussion of any actions taken by the existing licensee related to the project which affect the public.

(8) A summary of the ownership and operating expenses that would be reduced if the project license were transferred from the existing licensee.

(9) A statement of annual fees paid under Part I of the Federal Power Act for the use of any Federal or Indian lands included within the project boundary.

(1) Information Specified in H(a)

See Exhibit H(a).

(2) Safety Measures

(i) Operation of the Big Creek Powerhouse Nos. 1 & 2 Project

Operation of the Big Creek Powerhouse Nos. 1 & 2 Project is fully automated and may be controlled either locally from each powerhouse, or remotely from the non-Project Big Creek Powerhouse No. 3 Control Center (FERC Project No. 120).

A Station Order Binder is maintained at each of the Project powerhouses. This document includes individual site specific plans (Station Orders) outlining actions and considerations for high water flow events at each station and/or its associated head and tail works. The Station Orders provide for contingency planning and response to both planned and unplanned project high water flow events. This includes the potential for a single event or, when considered in aggregate, for multiple Powerhouse high water and/or flooding circumstances.

If flooding of Powerhouse No. 2 is imminent, several measures are implemented to prevent water damage to infrastructure and equipment. These measures include: closing drain line in rigger's loft between Units No. 3 and 4, before the Dam 5 water elevation reaches spill; closing the 20-inch overflow valve into the powerhouse cistern (if needed); switching the cooling water supply to the emergency supply from the penstock; monitoring the flow through the bearings and U-Fin tubes for plugging; draining miscellaneous oil containments at the powerhouse; checking and cleaning the cooling water filters, as necessary; and monitoring the Big Creek No. 2 penstock pressures.

If spill conditions are anticipated at Dam 4, the basement flood gates at Powerhouse No. 1 are closed. The maximum spill limit over Dam 4 is 2.5 feet above the flashboards at any powerhouse load. The flashboards at the dam are removed, as necessary, during spill periods to maintain conditions within this limit.

The entire “Big Creek Hydroelectric System,” including the Big Creek Powerhouse Nos. 1 & 2 Project, is operated together in a coordinated manner to maximize the hydroelectric power produced from the available water supply and to augment the operation of the federally operated Millerton Reservoir (downstream) as appropriate.

A safety/security assessment was completed for the Big Creek Powerhouse Nos. 1 & 2 Project in 2003 and a critical asset vulnerability assessment was completed in 2004. Both of these assessments were updated in April 2006. Security devices have been installed to protect the Project from acts of terrorism, and the Emergency Action Plan (EAP) for each powerhouse includes response measures for emergencies related to both natural causes and acts of terrorism. A copy of the EAP is maintained at each of the Project powerhouses and at the Big Creek Powerhouse No. 3 Control Center.

(ii) Downstream Public Safety

If a potentially hazardous condition exists or dam failure is imminent, the EAP is implemented and operations personnel and the SCE Energy Control Center are contacted. The situation would then be communicated by Control Center personnel to SCE Hydro Generation Division Management, Pacific Gas & Electric, the U.S. Bureau of Reclamation, the California Office of Emergency Services, the California Highway Patrol, and the Fresno and Madera County Sheriffs’ Departments. SCE Hydro Division management would immediately notify FERC and the California Division of Safety of Dams (DSOD). The emergency command center would be immediately established at the Northern Hydro Region Office at Big Creek by SCE personnel to coordinate communications and actions of SCE personnel and each involved agency. At each step of the communications network, an assessment will be made to determine whether the emergency situation requires immediate action and who is responsible for taking such action.

(iii) Changes Affecting the Emergency Action Plan

Copies of the Emergency Action Plan (EAP) for each powerhouse are kept at Big Creek Powerhouse Nos. 1 and 2 and at the non-Project Big

Creek Control Center (FERC Project No. 120). The EAPs for each of the Project powerhouses are reviewed and updated annually. SCE has no current plans to change the operation of the project or any plans for downstream development that might affect the existing Emergency Action Plans.

(iv) Monitoring Devices

Pressures near the bottom of the penstocks at each powerhouse are continuously monitored. If the pressure in the penstocks drops below a preset level from the normal operation pressure, an alarm is activated at the non-Project Big Creek Control Center at Powerhouse No. 3 (FERC Project No. 120). The operator would acknowledge the alarm and review other system parameters such as a drop in generation or unit flow, and after evaluating the system, make a decision on whether to shut the water conveyance system down.

Water levels in Huntington Lake and the Dam No. 4 impoundment are continuously monitored by sensors. The sensors are used to determine whether dam failure has occurred. If water levels drop at rates faster than preset levels, an alarm is activated at the non-Project Big Creek Control Center at Powerhouse No. 3 (FERC Project No. 120).

The Project is not staffed, although Powerhouse Nos. 1 & 2 and Dams 1, 2, 3, 3a, and 4 are visited weekly by operations personnel. All Project facilities are inspected by SCE personnel at least once a year. The California Department of Water Resources, Division of Safety of Dams, and FERC inspect the Project on an annual basis.

Dams 1, 2, 3, 3a, and 4 are inspected after significant seismic events. SCE inspects any dam that is within 50 miles of an event of magnitude 5.0 or greater.

A description of the monitoring equipment associated with Dams 1, 2, 3, and 3A is provided below. No instrumentation has been installed at Dam 4 and, as indicated in the *Eighth Five-Year Safety Inspection* dated April 2002, no significant deficiencies have been noted in the performance of the dam, so instrumentation is not considered necessary. The water level within the Dam 4 impoundment is monitored by a continuous water stage recorder.

Dam 1

A. Seepage

Seepage at the dam is monitored using a 90-degree V-notch weir situated at the downstream toe of the dam. Discharge measurements at the weir are collected twice each month when snow cover does not prevent access.

Groundwater conditions at the dam are monitored using 2 piezometers that are situated in the downstream buttress fill. Groundwater measurements are collected annually from the piezometers.

B. Seismic Monitoring System

Seismic activity in the Project area is monitored by a K2 strong-motion accelerograph at Balsam Meadow Dam.

C. Water Levels, Turbines, and Generators

Water levels in Huntington Lake and the mechanical and electrical settings of the turbines and generating equipment associated with the Project are monitored remotely at the non-Project Big Creek Control Center (FERC Project No. 120).

Dam 2

A. Seepage

Seepage at the dam is monitored, using a 90-degree V-notch weir situated at the downstream toe of the dam. Discharge measurements at the weir are collected twice each month when snow cover does not prevent access.

Groundwater conditions at the dam are monitored using 2 piezometers that are situated in the downstream buttress fill. Groundwater measurements are collected annually from the piezometers.

B. Seismic Monitoring System

Seismic activity in the Project area is monitored by a K2 strong-motion accelerograph at Balsam Meadow Dam.

C. Water Levels and Conduit Pressure

Water levels in Huntington Lake and pressure in Tunnel No. 1 are monitored remotely at the non- Project Big Creek Control Center (FERC Project No. 120).

Dam 3

A. Seepage

Seepage at the dam is monitored, using a 90-degree V-notch weir situated at the downstream toe of the dam. Discharge measurements at the weir are collected twice each month when snow cover does not prevent access.

Groundwater conditions at the dam are monitored using 2 piezometers that are situated in the downstream buttress fill. Groundwater measurements are collected annually from the piezometers.

B. Seismic Monitoring System

Seismic activity in the Project area is monitored by a K2 strong-motion accelerograph at Balsam Meadow Dam.

C. Water Levels

Water levels in Huntington Lake are monitored remotely at the non-Project Big Creek Control Center (FERC Project No. 120).

Dam 3A

A. Seepage

Seepage at the dam is monitored using a discharge pipe located below the downstream toe of the dam. Prior to July 1999, the discharge was recorded monthly when snow cover did not prevent access. However, the flowline collapsed in July 1999 and monitoring has not been conducted since that time.

B. Seismic Monitoring System

Seismic activity in the Project area is monitored by a K2 strong-motion accelerograph at Balsam Meadow Dam.

C. Water Levels

Water levels in Huntington Lake are monitored remotely at the Big Creek Control Center.

(v) Employee and Public Safety

Eight lost-time industrial accidents have been recorded at the Project in the last ten years. These accidents consist of the following:

- March 21, 1995 – Shoulder Injury
- April 18, 1996 – Chemical in Eyes
- April 30, 1996 – Back Injury
- May 6, 1996 – Broken Leg
- August 22, 1996 – Wrist Injury
- January 10, 2000 – Broken Ankle
- December 11, 2002 – Strained Achilles Tendon
- November 24, 2004 – Ganglion Cyst
- September 16, 2005 – Cumulative Back Injuries

In the past 10 years, one public death was recorded within the Project boundary. This incident consisted of a drowning in Huntington Lake that occurred on August 8, 1995. A Public Safety Plan is on file with the FERC that identifies all public safety devices installed at the Project.

(3) Project Operation and Constraints

Big Creek Powerhouse No. 1 Units 1 and 2 commenced operation in 1913, and Units 3 and 4 went online in 1923 and 1925, respectively. Big Creek Powerhouse No. 2, Unit 3, commenced operation in 1913. Unit 4 went into service in 1914. Unit 5 went online in 1921. Unit No. 6 commenced operation in 1925. The specifications for the generators and turbines associated with each powerhouse are provided in Exhibit A, Section (3).

Operation of the Big Creek Powerhouse Nos. 1 & 2 Project is automated and may be controlled either locally from the each powerhouse or remotely from the Big Creek Powerhouse No. 3 Control Center.

In general, and as seasonal conditions allow, Huntington Lake is operated within 3 feet of normal full pool between Memorial Day and Labor Day of each year, and is typically maintained within approximately 1-foot of full pool. In the winter, the reservoir can be drawn down as much as 50-70 feet. The Dam 4 reservoir serves as a forebay for Big Creek Powerhouse 2, with only a few feet of drawdown utilized.

Project operation and constraints are discussed further in Exhibit B, Section (1).

(4) Project History and Upgrades

The Project was constructed between 1912 and 1917 as follows:

- The initial phase of construction for Dams No. 1, 2, and 3 commenced in the Summer of 1912 and was completed in the Fall of 1913.

- Dam No. 4 was constructed in 1913.
- The construction of Powerhouse 1 commenced in the spring of 1913 and was completed in October 1913.
- The construction of Powerhouse 2 commenced in the spring of 1913 and was completed in December 1913.
- The second phase of Project construction occurred in 1917 and consisted of increasing the crest height of Dams No. 1, 2, and 3 by 38 feet and the construction of Dam No. 3A.

A discussion of the Project upgrades and modifications since start-up is provided in Exhibit C, Section 1(iii).

(5) Unscheduled Outages

Five years of unscheduled (forced) outages, 2000 to 2005 inclusive, are listed below in Table H(b)-1.

(6) Record of Compliance

There have been no incidents of non-compliance in the past 20 years.

(7) Actions Related to the Project Which Affect the Public

In the event of an emergency, SCE personnel, through the U.S. Forest Service and the California Highway Patrol, notify the public and the Sheriff's Office. Public safety devices (e.g., fences, locked gates, signs, grab lines, sirens) are installed where necessary to protect the public.

(8) Summary of Ownership and Operating Expenses

If the Project license were transferred, ownership and operating costs that would be reduced include:

Operation and Maintenance Costs	
(Annualized over License life)	$ 7,107,462
Depreciation (2005)	1,441,469
Property Taxes (2005)	425,702
A&G Expenses	
(Calculated from 2005 Net Invest)	$ 494,936
Total	$ 9,469,569

(9) Annual Fees

The annual fees for FERC Bill Year 2006, paid under part I of the Federal Power Act, are as follows:

Water for Power	$ 795,523
Federal Land Rents	173,275
Total	$ 968,798

Water for Power – charges for the purpose of reimbursing the United States for the costs of the administration of Part I of the Federal Power Act.

Federal Land Rents – annual fees paid for the occupancy of federal lands for reservoirs, dams, flumes, forebays, penstocks, and powerhouses.

Table H(b)-1. Unscheduled Outages - 2000 to 2005.

PH No.	Unit	Date/Time	Hours Off	Reason	Corrective Action
BC2	5	2/2/00 10:47	25.3	Bearing oil leak.	Adjusted high pressure oil supply flow.
BC2	4	9/4/00 16:00	47.4	Failed needle stem seal.	Replaced seal, serviced excitation.
BC1	4	10/18/00 13:24	0.4	New RTU testing problem with Ovation.	Reset control points.
BC1	1	10/26/00 4:56	130.4	Left hand needle packing failed flooding generator leads.	Removed grounded lead and returned unit at 9.5mw capacity.
BC1	2	10/26/00 4:56	12.6	No.1 unit L.H. needle stem packing failed flooding No.2 gen. Pit.	Evacuated water from gen. Pit. Repacked needle stem.
BC1	1	11/12/00 6:07	1.8	Trash in rotor fan.	Removed trash and restarted unit
BC1	1	11/29/00 19:58	26.7	B phase generator cable failed.	Replaced cable
BC1	3	12/11/00 7:47	57.5	Penstock leak	Repacked expansion joint.
BC1	4	12/21/00 10:40	4.3	R.H. speeder motor problem.	Repaired speeder motor.
BC2	5	9/10/01 13:56	3.3	Oil in generator pit.	Removed oil from pit.
BC1	2	9/19/01 10:47	0.9	Bad slip ring brushes.	Replaced brushes.
BC1	3	10/15/01 8:08	5.3	Penstock leak	Repaired leak.
BC1	4	5/1/02 13:57	1.0	Erratic governor operation	Adjusted L.H. Governor.
BC1	4	5/14/02 14:42	0.8	Bad short brushes.	Replaced short brushes
BC2	4	9/18/02 13:40	9.4	Failed TSO valve stem packing.	Replaced packing.
BC1	4	9/23/02 15:52	1.9	High bearing temperature.	Adjusted alarm point due to warm cooling water temps.
BC1	4	9/24/02 12:52	1.9	High bearing temp.	Adjusted alarm point due to warm cooling water temps.
BC1	2	3/8/03 5:00	156.8	220KV CB replacement at BC# 2.	Replaced 220 kV CB
BC2	4	3/19/03 14:50	1.6	Leak in L.H. press. reg. control piping.	Repaired piping.

Table H(b)-1. Unscheduled Outages - 2000 to 2005 (continued).

PH No.	Unit	Date/Time	Hours Off	Reason	Corrective Action
BC1	2	4/2/03 8:51	6.1	Hot bearing	Supplemented cold water supply until acid flush can be done.
BC1	4	4/15/03 8:49	7.5	Penstock expansion joint leak.	Repacked expansion joint.
BC2	6	4/30/03 0:50	3.0	Gen. field ground.	Cleaned excitation equipment.
BC1	4	11/22/03 0:17	61.8	Hot L.H. Bearing	Repaired cooling water system
BC2	6	12/18/03 20:31	62.3	Solid state excitation ground and failed meggar.	Cleaned field poles.
BC1	3	6/28/04 19:00	23.3	Complete expansion joint re-pack. Extended due to non-concentric condition.	Repacked expansion joint
BC1	4	9/24/04 10:27	3.0	TSO valve control water piping leak	Repaired leak.
BC2	3	02/28/05 13:32	2.4	Inspect Neutral Ground Equipment	Inspect Neutral Ground Equipment
BC2	3	03/03/05 8:47	6.0	Pressure Regulator Problems	Cleaned Pilot Valve
BC2	4	03/07/05 9:32	214.2	Pressure Regulator Problems	Repaired Pilot Valve
BC2	3	03/16/05 9:10	3.4	Pressure Regulator Problems	Repaired Pressure Regulator
BC1	4	03/29/05 6:14	4.1	Governor Problems	Repaired Governor
BC2	5	03/30/05 15:43	3.2	Governor Problems	Repaired Governor
BC1	2	10/04/05 19:07	16.4	Penstock Leak	Repaired Penstock
BC2	3	10/24/05 16:51	48.1	R.H. Needle Stem Packing Failed	Replaced Packing