4.3 HYDROLOGY AND WATER QUALITY

4.3.1 INTRODUCTION TO HYDROLOGY AND WATER QUALITY

This section describes water resources at Pacific Gas and Electric Company's hydroelectric facilities and associated Watershed Lands in Northern and Central California, and addresses how utilization and management of the water resources for power production affects the physical environment and other beneficial uses. The section provides an overview of discretionary and non-discretionary factors affecting water use and management, including applicable regulatory constraints. The section then addresses the following for each asset: the location of the drainage basin, the flow of water through the different facilities, a general discussion of water quality, physical characteristics of Pacific Gas and Electric Company's water conveyance systems and capacities, maximum powerhouse capacities, and considerations, including specific regulatory constraints, that affect the management of water for power production and other purposes.

Pacific Gas and Electric Company's hydroelectric facilities were built, for the most part, in the early and mid part of the 20th Century. The existing facilities and their operations are integrated into the water supply system for the State and can affect water quality in the surrounding watershed.

4.3.1.1 Water Use

Water is used at Pacific Gas and Electric Company's hydroelectric facilities primarily for the nonconsumptive purpose of generating electric power. Other uses include minor consumption at powerhouses and recreational facilities (e.g., for drinking water, sanitation, or maintenance activities), provision of recreational opportunities, sale or delivery to other parties, and fish and wildlife preservation and enhancement. Other users of the waterway may use water (and, in some cases, Pacific Gas and Electric Company facilities such as reservoirs) for these same uses, and may also use the water for irrigation and public water supply. Pacific Gas and Electric Company does not pump groundwater for power generation purposes, although groundwater may in some cases naturally contribute to surface flows on a river system.

Pacific Gas and Electric Company's uses of the Watershed Lands have less potential to affect water resources than the hydroelectric facilities. The majority of the Watershed Lands are undeveloped. With the exception of some canals and flumes that may cross certain parcels, these Watershed Lands do not contain any generation facilities or support activities that result in significant consumptive or non-consumptive uses of water (PG&E Co., 1999).

Uses of Pacific Gas and Electric Company's Watershed Lands include grazing, recreational activities, housing, and timber harvesting. These land uses do not divert or use water in volumes great enough to result in major effects on water resources. Grazing activities are typically seasonal and occur on areas that are supported by natural rainfall. The licensees have the option to request service from a local water district to meet their needs (*i.e.* irrigation, drinking, sanitary facilities, general usage, etc.) but this is more the exception than the norm. Occupants of recreational home sites authorized by Pacific Gas and Electric Company utilize either wells or natural springs located on the property. Even where Pacific Gas and Electric Company maintains water rights for water in streams or other tributaries crossing the Watershed Lands, Pacific Gas and Electric Company does not typically authorize the licensor/lessor to draft or divert water from those sources except under very specific circumstances. Where specific permissions have been granted for use of water from the site or through Pacific Gas and Electric Company's water rights, they are discussed in the following sections.

There are no significant uses of water resources associated with timber management, although these activities have the potential to affect watercourses through erosion, debris, and heavy equipment use. Such effects of timber management on water resources are addressed through the THP process. Use of on-site water for the watering of roadways at select locations could be required as a condition of a THP when water is available.

4.3.1.2 Sources of Water Resources Impacts at Hydroelectric Facilities

Use and management of water resources at a typical hydroelectric facility can affect both the natural environment in the vicinity of the facilities and other beneficial users of water resources. Use of water resources at hydroelectric facilities has the potential to affect the natural environment and other uses through the diversion and impoundment of water and the manipulation of water flow fluctuations through controlled releases and uncontrolled spills.

Impacts on the Natural Environment

Pacific Gas and Electric Company's hydroelectric facilities divert water from the natural stream channel and utilize conveyance systems to pass the water through powerhouses, eventually returning it to the natural stream. Diversion can impact water resources by reducing the flow levels in the natural stream, which can affect the use of the water resource by fish and wildlife. In addition, diversion intake structures can potentially impact fish by causing impingement of fish on screens and trash racks and entrainment of fish in powerhouse conveyances. Impacts from water diversion activities on biological resources are discussed in Sections 4.4 and 4.5.

Water impoundment's artificially alter natural stream conditions and change a river environment to a lake environment. Reservoirs can capture bedload sediments, resulting in armoring and/or scour in downstream reaches. Dams can also reduce downstream nutrients and substrate migration, cause reductions in dissolved oxygen for fish, block pathways for migrating fish and pose hazards for wildlife resources. Management of reservoir sediment (sluicing, flushing, dredging, etc.) and temporary operations associated with repair activities can also affect water quality downstream of Pacific Gas and Electric Company facilities.

Operation of storage reservoirs, including controlled releases and uncontrolled spills, can lead to thermal stratification, supersaturation, and changes in dissolved oxygen levels, all of which adversely impact fisheries resources. Impoundment may also lead to increased water temperatures due to thermal heating. These effects of impoundment on biological resources are discussed in detail in Section 4.4. In addition to impacts on biological resources, regular release of impounded water can decrease vegetation along the shoreline, leading to an increase in erosion. Erosion can contribute to sedimentation problems.

Impacts on Other Beneficial Uses

Pacific Gas and Electric Company's utilization and management of water resources at its hydroelectric facilities have the potential to affect other beneficial uses of these resources. Although Pacific Gas and Electric Company's water rights are largely nonconsumptive, the infrastructure related to impoundment, diversion, and power generation may affect other water users. Hydroelectric facilities may function as an integral component of the water supply and distribution system for domestic water supplies and irrigation in some areas. In such cases, Pacific Gas and Electric Company typically has agreements with the affected water users regarding the volume, timing, and location of diversions.

In addition, hydroelectric facilities create and impact water-related recreational opportunities. Reservoirs and other facilities can affect recognized beneficial uses such as boating, fishing, and swimming. Hydroelectric diversion and conveyance systems can also have potentially adverse impacts on certain recreational activities such as river rafting by altering natural stream flows, creating physical obstacles such as dams, and creating lake habitat from the river environment. For further discussion of recreational uses, please see Section 4.6.

4.3.1.3 Water Management

Water management refers to operational decisions to store, release, and spill available water, and all factors relating to the timing or quantity of water stored, released and spilled. In addition to maximizing revenue, water management must consider other uses such as recreation, habitat enhancement, irrigation and other domestic uses, and the need to handle emergency situations such as floods, are also taken into account in an overall water management strategy. Note that many of these issues are not typically addressed by FERC regulatory requirements and as such are largely voluntary considerations on the part of the operator.

A key consideration in water management strategies is hydrological and operational links among specific facilities. Hydrological linkage exists where facilities are located on an interrelated system of watercourses, such that actions at upstream facilities can directly impact operations and water management at downstream facilities, and must be taken into account for safety purposes and economically efficient operations. In some cases, Pacific Gas and Electric Company's facilities are hydrologically linked with facilities owned by others, which can create the need for coordination or communication between the separately owned facilities.

Some facilities are not hydrologically linked, but are centrally or remotely operated and monitored from a common facility known as a switching center (usually a centrally-located powerhouse). This is generally done for efficiency purposes, since it is neither necessary nor ideal to staff every facility at all times. Central operation and monitoring helps operators easily coordinate operations of a number of facilities to ensure safe and economically efficient operations.

Beyond the efficiency and safety elements involved at hydrologically linked facilities or facilities with centralized operations, water management involves a complex mix of discretionary and non-discretionary elements.

Non-discretionary Elements of Water Management

Non-discretionary factors affecting water management include water availability, physical system characteristics, and regulatory conditions. These three factors can be described as follows:

Water Availability

Water availability is determined by factors affecting water management that are beyond the generators' immediate discretionary control, such as water rights held or claimed by the generator and other upstream and downstream users and contractual obligations to deliver water to other beneficial users (i.e., for irrigation or consumptive use). The amount of water available seasonally and yearly can vary widely depending on precipitation, which is beyond Pacific Gas and Electric Company's control and cannot be accurately predicted in advance. The combination of natural factors (precipitation) and legal water obligations together dictate the amount of water that is available for generation over a given time period, and provide the starting point for water management.

Physical System Characteristics

The amount of water that can be used for generation is affected by the physical characteristics of the generating system. Whether a given facility has storage and conveyance capability (as opposed to being run-of-the-river [ROR]), the size of the storage and conveyance facilities, hydrological linkage with other facilities, and other unique characteristics (such as pumped storage capability) all are fixed factors beyond a particular operator's immediate control, that must be factored into a water management strategy. Physical system characteristics, together with water availability, control current operating decisions and are likely to continue to constrain operations in the foreseeable future. Although Pacific Gas and Electric Company and a new owner would have some discretion to consider physical modifications, modification of physical facilities is expensive and requires an often extensive regulatory approval process.

Regulatory Conditions

Because hydroelectric facilities must coexist with other beneficial uses of a water way, FERC and, in some instances, other Federal and State agencies have the authority to set regulatory conditions that control nearly all aspects of hydroelectric facility operation. Depending on the given constraints of a particular system (e.g. physical constraints and factors influencing water availability), FERC may find it necessary to set license conditions that mandate minimum flows, reservoir levels, ramping rates, temperature limitations, and provision of recreational facilities. Once set, these conditions bound the discretion of an operator to manage water at a given facility or system of linked facilities in a way that is harmful to the environment or disregards other beneficial uses of a waterway.

Effect of Non-Discretionary Constraints

Taken together, these three non-discretionary constraints create a set of operating parameters, within which variation caused by both natural factors and discretionary water management must remain. Each facility has its own unique combination of these factors, and thus the set of constraints for each facility may be different. In some cases, regulatory conditions, such as minimum flows, may be the factor that is most influential for operations at a given point in the system. In other places in the system, regulatory requirements may be easily met and physical constraints, such as conveyance system capacity, may play a more important role in determining operations. Contractual obligations to deliver water along a watercourse may also influence the amount of water available for a series of powerhouses in a linked system. The asset–specific discussions below identify the most important constraints that influence operations at individual powerhouses and other facilities. While the existence of non-discretionary constraints does not eliminate all discretionary elements in running a hydroelectric system, they do influence in predictable ways the manner in which the system is operated.

Discretionary Elements of Water Management

A number of discretionary elements go into water management over a given time frame. In managing water for hydropower purposes, hydroelectric facility operators must make predictions about market conditions and water that will likely be available for generation. At storage facilities, operators have incentives to maximize generation at times when it will yield the highest net revenues, and must determine, subject to applicable constraints, when to store and release water and how much water to store and release to meet this goal. In contrast, run-of-the-river facilities require less discretionary decision-making on the part of the operator, because water cannot be stored and must be used when available or be lost for generation purposes.

Water management strategies must also account for unforeseen and unexpected events. Decisions such as how much to draw down a reservoir to make room for anticipated runoff (which cannot be accurately predicted except in the case of seasonal snow melt runoff) and the ability to divert water away from a problem location in the system all must be considered in advance. In many cases, physical components, such as spill gates, have been designed into the system to help respond to emergency circumstances.

One emergency circumstance that occasionally (but infrequently) affects water management activities at Pacific Gas and Electric Company's hydroelectric facilities is flood control. All of Pacific Gas and Electric Company's dams serve as storage or diversion facilities for hydroelectric power production. None of the dams are operated for use as flood control facilities. The reason is that these dams, for the most part, are geographically located in the steep upper reaches of rivers and streams that drain the west slope of the Sierra Nevada. As such, these dams generally are not designed to impound large volumes of water needed to serve as flood control facilities. Most of these facilities rely on seasonal rain/snowmelt runoff to completely fill to their maximum storage levels and the available stored water is subsequently withdrawn for power production annually.

During flood events, Pacific Gas and Electric Company attempts to anticipate the volume of flood inflow and take all necessary actions to operate reservoirs in a way that minimizes the risk of downstream flooding. Pacific Gas and Electric Company also makes notification to emergency services, such as the Office of Emergency Services (OES), so that they may inform, and if necessary, evacuate downstream inhabitants. During unplanned releases of large volumes of water, hydroelectric operators may activate Pacific Gas and Electric Company's Emergency Action Plan (EAP).

In the Motherlode and DeSabla Watershed Region, Pacific Gas and Electric Company attempts to influence local meteorology by engaging in limited cloud seeding designed to increase average annual precipitation within certain watersheds where facilities are located. The cloud seeding program is used to augment precipitation by providing nuclei for formation of snow or raindrops. The cloud seeding facilities typically consist of a stainless steel burner, propane tanks, a container of cloud seeding solution (consisting of acetone, silver iodide, ammonium iodide, and water), and control and monitoring devices. In certain instances, Pacific Gas and Electric Company cooperates in the cloud seeding activities of other persons or governmental agencies by paying a portion of the annual costs of such activities. Cloud seeding activities may have an impact on local meteorology by enhancing the amount of precipitation within the watersheds affected by such activities.

Hydrometeorologic Data Collection

To measure the amount of water available at various points in the system, Pacific Gas and Electric Company maintains gaging stations that are used to measure reservoir elevations, canal flows and stream flows. Reservoir gaging stations are used to help coordinate the operation of hydroelectric generating facilities. Stream gaging stations located upstream from reservoirs provide information on inflows to reservoirs. Canal and stream gages downstream from reservoirs measure releases and accretion flows, and may be used to record compliance with stream flows required by the terms of the applicable FERC license. Pacific Gas and Electric Company maintains approximately 530 in-stream gauges (PG&E Co., 1999).

Pacific Gas and Electric Company participates in various programs for measuring the water content of snow pack in the higher elevations of the watersheds where the facilities are located. A snow course is essentially a pre-determined, usually straight-line, course of several hundred yards in length, typically located in a relatively flat high altitude meadow. From these areas, periodic measurements of snow depth and moisture content are regularly made, recorded and transmitted to the California Department of Water Resources (DWR). There are presently approximately 330 snow courses maintained by DWR, of which Pacific Gas and Electric Company monitors approximately 50 (PG&E Co., 1999). Taking measurements from the same areas over many years can reveal correlations between snow depth and moisture content and subsequent runoff and recharging of subterraneous aquifers. These correlations can be modeled by various parties for their particular use, including modeling by Pacific Gas and Electric Company to assist in predicting reservoir levels, ground water aquifer recharging, water storage and spillage requirements, and probable levels and intensity of stream flows. DWR collects and disseminates the information, but modeling of the data is unique and is, accordingly, proprietary. The State of California publishes substantial information resulting from snow course data collected throughout the State. The data is available through the California Data Exchange Center or from the following Internet site: http://cdec.water.ca.gov. Most of the snow courses maintained and operated by Pacific Gas and Electric Company are on USFS land and are operated under permits issued to the DWR, which delegates to Pacific Gas and Electric Company responsibility to maintain and operate the snow courses. A few, notably in the Kings Crane-Helms Watershed Region, are licensed directly to Pacific Gas and Electric Company by the USFS.

4.3.2 SYSTEM-WIDE REGULATORY CONTEXT

Given the fact that hydroelectric facility operations can affect water resources, an extensive regulatory system is in place to ensure that operations remain within parameters that balance the interests of hydroelectric production, preservation of the environment, and the interests of other beneficial water users. Agencies with regulatory authority over water resources at Pacific Gas and Electric Company's facilities include FERC, USACE, the State Water Resources Control Board (SWRCB), Regional Water Quality Control Boards (RWQCB), and California Department of Fish and Game (CDFG).

4.3.2.1 FERC Regulation

FERC is the lead regulatory authority responsible for setting operating conditions at hydroelectric facilities, which it accomplishes through the licensing (for new facilities) and relicensing process. Specific conditions in FERC licenses are dependent in part on the age of the license, and also on ecological conditions of a facility. FERC relicensing and amendment processes are the primary mechanisms by which environmental conditions have been set in many of Pacific Gas and Electric Company's licenses.

To ensure that hydroelectric facilities are operated in a way that is protective of water resource interests in addition to power production, FERC sets license conditions, where appropriate, that regulate elements such as reservoir levels, minimum flows, ramping rates, temperature, turbidity, and recreation. FERC monitors the licensee's compliance on an ongoing basis. It also conducts operations inspections annually and environmental and public use inspections (EPUIs) at least once every six years. The relicensing process provides an opportunity for FERC to revisit license conditions set previously, to ensure that they are properly protective of the environment. Many of Pacific Gas and Electric Company's FERC licenses contain reopener provisions that can provide flexibility to alter conditions mid-license. FERC also requires licensees to consult with State and Federal agencies during the license term if changes are required to the facility or mitigation plans under the license.

In issuing an original or new license, FERC looks at available data and determines what constraints apply to each facility (such as physical constraints) and the natural characteristics of the system. FERC then considers what additional conditions are needed to ensure that hydroelectric facilities remain compatible with other beneficial uses and preservation of the environment. As a result of this process, different facilities end up with unique conditions designed to address specific issues. For example, a base-loaded run-of-the-river facility may not require a license condition (such as a ramping rate) regulating high peaking flows.

4.3.2.2 Non-FERC Regulation of Water Resources

Water Quality Certification and Order 464

The Federal Clean Water Act (33 USC §1251, et seq.) was enacted "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (33USC §1251(a)). Section 101(g) (33 USC §1251(g)) requires Federal agencies to "cooperate with state and local agencies to develop comprehensive solutions to prevent, reduce and eliminate pollution in concert with programs for managing water resources". Section 401 (33 USC §1341) requires every applicant for a Federal license or permit to provide the responsible Federal agency with certification that the facility will be in compliance with specified provisions of the Clean Water Act, including section 303 ("Water Quality Standards and Implementation Plans", 33 USC §1313); directs the State agency responsible for certification to prescribe effluent limitations and other limitations necessary to ensure compliance with the Clean Water Act and with any other appropriate requirement of State law; and provides that State certification conditions shall become conditions of any Federal license or permit for the facility.

The State Water Resources Control Board (SWRCB) was created by the Legislature in 1967. The mission of the SWRCB is to ensure the highest reasonable quality for waters of the State, while allocating those waters to achieve the optimum balance of beneficial uses. The joint authority of water allocation and water quality protection enables the SWRCB to provide comprehensive protection for California's waters.

There are nine Regional Water Quality Control Boards (RWQCB) in California. The mission of the RWQCBs is to develop and enforce water quality objectives and implementation plans which will best protect the beneficial uses of the State's waters, recognizing local differences in climate, topography, geology and hydrology. The California RWQCBs have adopted, and the SWRCB has approved, Water Quality Control Plans (Basin Plans) for each watershed basin in accordance with provisions of section 303 of the Clean Water Act, related to the establishment of water quality standards and planning (33 USC §§1313). Basin Plans identify beneficial uses of the waters within each region and standards to protect those beneficial uses.

The SWRCB is the agency responsible for water quality certification in California (section 13160 of the California Water Code); and has delegated this function to the Executive Director by regulation (section 3838 of Title 23 of the California Code of Regulations (CCR)). In order to make its 401 certification decision, the SWRCB must have adequate information. It is the obligation of the permit or license applicant to provide sufficient information that establishes there is a reasonable assurance that the discharge will comply with applicable provisions of the Clean Water Act and State Water Quality Standards. The required information will depend upon the circumstances and permit or license involved.

Under the authority of the Federal Power Act, as amended by the Electrical Consumers Protection Act the Federal Energy Regulatory Commission (FERC) has the responsibility of issuing and enforcing licenses for non-Federal hydroelectric power plants. FERC issues licenses for 30 to 50 years for constructing, operating, and maintaining hydroelectric facilities under it jurisdiction

On February 11, 1987, the FERC issued a Final Rule for “Waiver of the Water Quality Certification Requirement of Section 401(a)(1) of the Clean Water Act” (Docket No. RM85-6-00, Order 464). Under Order 464, FERC interpreted Section 401(a)(1) of the Clean Water Act to hold that a request for water quality certification is deemed waived if a certifying agency has not granted or denied the license applicant’s certification request within one year after the certifying agency receives the request.

Order 464 was applicable to all hydroelectric license applications filed after the effective date of the rule (May 9, 1987). With regard to pending applications that did not have 401 water quality certifications, FERC retroactively applied the rule to requests for certifications that were pending more than one year. As a consequence of the retroactive application of that rule, states were precluded from taking action on certification requests that had been pending more than one year. This action disregarded State regulations that deemed a request for water quality certification complete only after all required information necessary for a certification decision (hydrology, temperature monitoring data, instream flow studies) was submitted to the State. FERC applied Order 464 to 34 hydroelectric facilities in California. Six of those retroactively applied waivers were Pacific Gas and Electric Company facilities.

Hydroelectric facilities are subject to regulation of dredge and fill and streambed alteration activities, under State and Federal law. Section 404 of the CWA regulates discharge of dredge and fill materials into the waters of the United States, and activities resulting in this type of discharge are subject to permitting requirements of the USACE. Most of Pacific Gas and Electric Company's maintenance activities can be done under the Corps Nationwide Permit program, but in some cases an individual permit is required. All Nationwide Permits issued by the USACE for FERC projects require an individual 401 certification or waiver of certification by the SWRCB or in some cases the RWQCB. The licensee cannot undertake the activity proposed under the Nationwide Permit without first receiving a certification or waiver from the State. In addition to Federal and SWRCB regulation of these types of activities, Pacific Gas and Electric Company has historically obtained streambed alteration agreements prior to conducting activities that may divert, obstruct, or change the natural flow or bed, channel, or bank of rivers, streams, or lakes. (CDFG Code §§ 1601 and 1603.)

Water quality is also regulated by RWQCBs which have the authority to issue Waste Discharge Requirement (WDR) Orders and National Pollutant Discharge Elimination Systems (NPDES) permits governing the discharge of pollutants to soil, groundwater, and surface water. While WDR Orders are not commonly issued for hydroelectric plant operations, construction and maintenance activities that require USACE permits may be issued WDR orders.

Powerhouses not licensed by FERC are subject to applicable Federal, State and local laws and regulations, including permitting requirements. These hydroelectric facilities may include conditions associated with water rights granted by the SRWCB, and are additionally subject to regulation under the SWRCB *Guidelines for Protection of Water Quality During Construction and Operation of Small Hydro Projects* (Small Hydro Guidelines, October 1983). These Guidelines are intended to ensure protection of all beneficial instream uses, including water quality, aquatic and riparian habitat, and recreational and aesthetic uses. The Small Hydro Guidelines regulate both construction at these facilities and ongoing operations affecting water quality. Other agencies that regulate the three non-jurisdictional Pacific Gas and Electric Company assets include the SWRCB/RWQCB, Division of Water Resources, the CDFG, California Occupational Safety and Health Administration (Cal OSHA), local Certified Unified Program Agencies (CUPAs), USFWS (if threatened or endangered species are impacted), the USACE, and local agencies.

Tables 4.3-1 through 4.3-5 document the status of 401 certifications for Pacific Gas and Electric Company facilities within each of the five regional bundles. The information in these tables was derived from conversations with SWRCB staff (SWRCB, 2000) and Pacific Gas and Electric Company files (PG&E Co., 2000e).

Table 4.3-1 Pacific Gas and Electric Company Hydroelectric Assets 401 Certification Status – Shasta Regional Bundle

Asset Name	FERC License No.	Date FERC License Expires	401 Certification Status	Comments
Hat Creek 1 and 2	2661	9/30/2000	Certificate No. 73-30 issued by SWRCB on 4/26/1973	On a FERC Annual License, therefore 1973 certification continues to apply. PG&E Co. requested a new certification or waiver from SWRCB on 8/29/2000 in expectation of a new license to be issued by FERC about 9/2001.
Pit 1	2687	12/31/1995	No certification due to water quality problems. See SWRCB letter of 12/8/1994 for issues.	On a FERC Annual License. SWRCB stated PG&E Co.'s application was complete on 1/12/1994, but denied certification due to water quality problems on 12/8/1994. PG&E Co. requested a certification or waiver from SWRCB on 12/6/1999 in expectation of a new license to be issued by FERC about 7/2001.
Pit 3, 4 and 5	233	10/31/2003	Deemed waived for existing license pursuant to section 401(a)(1) of the Clean Water Act	PG&E Co. requested certification on 3/22/1974. SWRCB did not take action within the one-year time period allowed. See PG&E Co. letter to FERC dated 11/22/1978. NOI for new license filed by PG&E Co. New license expected about 10/2005. 401 Certification from the SWRCB will be required.
McCloud-Pit	2106	7/31/2011	None	Licensed prior to implementation of the Clean Water Act. NOI to be filed by 7/31/2006 with an Application for New License to be filed by 7/31/2009. 401 Certification from the SWRCB will be required.
Kilarc-Cow Creek	606	3/27/2007	Certificate No. 78-24 issued by SWRCB on 10/4/1978	NOI to be filed by 3/27/2002 with an Application for New License to be filed by 3/27/2005. 401 Certification from the SWRCB will be required.
Battle Creek	1121	7/31/2026	Certificate No. 72-41 issued by SWRCB on 9/2/1972 and Certificate No. 79-12 issued by SWRCB for the Volta 2 Facility on 10/17/1979.	NOI to be filed by 7/31/2021 with an Application for New License to be filed by 7/31/2024. Pacific Gas and Electric Company has filed for a license amendment as part of the Battle Creek Salmon and Steelhead Restoration Project which will require 401 Certification from the SWRCB.

Source: Compiled by Roy Leidy, EIP Associates, 2000

Table 4.3-2 Pacific Gas and Electric Company Hydroelectric Assets 401 Certification Status – DeSabla Regional Bundle

Asset Name	FERC License No.	Date FERC License Expires	401 Certification Status	Comments
Hamilton Branch	Unlicensed	Unlicensed	Not required	
Upper North Fork Feather River	2105	10/31/2004	No specific certification, however, letter from Central Valley RWQCB dated 10/23/1984 states that no significant threat to water quality should result from the Oak Flat Powerhouse.	Certification deemed waived for Oak Flat PH pursuant to section 401(a)(1) of the Clean Water Act. Other elements of FERC 2105 pre-date Clean Water Act. NOI filed 10/31/1999. New license expected about 11/2005. 401 Certification from the SWRCB will be required.
Bucks Creek	619	12/31/2018	Certificate No. 72-59 issued by SWRCB on 11/24/1972	Central Valley RWQCB stated in a letter dated 6/5/1984 that the addition of the Grizzly Powerhouse did not require a certificate and that the PH would not adversely impact water quality provided the RWQCB's guidelines were followed (Resolution 83-135). NOI to be filed by 12/31/2013 with an Application for New License to be filed by 12/31/2016. 401 Certification from the SWRCB will be required.
Rock Creek-Cresta	1962	9/30/1982	Waived pursuant to FERC Order 464 (Docket No. RM85-6-00)	On Annual License. NOI filed 9/30/1977. Application for New License filed 9/26/1979. PG&E Co. requested certification on 5/13/1981. No response from RWQCB until 3/15/1985 when the Central Valley RWQCB stated that the operation of the facility should not adversely affect water quality provided that the RWQCB's guidelines were followed (Resolution No. 83-135). New license expected about 7/2001.
Poe	2107	9/30/2003	None	Licensed prior to implementation of the Clean Water Act. NOI filed on 9/30/1998 with an Application for New License to be filed by 9/30/2001. No request for 401 certification filed yet. New license expected about 10/2004. 401 Certification from the SWRCB will be required.
Lime Saddle	Unlicensed	Unlicensed	Not required	
Coal Canyon	Unlicensed	Unlicensed	Not required	
DeSabla-Centerville	803	10/11/2019	Certificate No. 78-23 issued by SWRCB on 10/2/1978. Central Valley RWQCB in a letter dated 7/1/1982 decided not to act on request for certification of the Toadtown Powerhouse addition, thus this facility is deemed waived.	NOI expected to be filed by 10/11/2004 with an Application for New License expected to be filed by 10/11/2007. 401 Certification from the SWRCB will be required.

Source: Compiled by Roy Leidy, EIP Associates, 2000

Table 4.3-3 Pacific Gas and Electric Company Hydroelectric Assets 401 Certification Status– Drum Regional Bundle

Asset Name	FERC License No.	Date FERC License Expires	401 Certification Status	Comments
Drum-Spaulding	2310	5/1/2013	None for older facilities that pre-date the Clean Water Act. Central Valley RWQCB took no action on requests for certification for five newer powerhouses, thus these facilities are deemed waived.	PG&E Co. applied for certification or waiver for the Newcastle, Christian Valley, Emigrant Gap and Fiddler Green powerhouses on 10/27/1981. Central Valley RWQCB decided not to act on request (letters of 12/15/1981 and 12/16/1981). PG&E Co. applied for certification or waiver for the Wise 2 Powerhouse on 5/12/1982. Central Valley RWQCB decided not to act on request (letter of 7/1/1982). 401 Certification from the SWRCB will be required for new license.
Narrows	1403	1/31/2023	Deemed waived pursuant to FERC Order 464	PG&E Co. application for certification filed with RWQCB on 4/4/1989. No formal action by Central Valley RWQCB. NOI expected to be filed by 1/31/2018 with an Application for New license expected to be filed by 1/31/2031. 401 Certification from the SWRCB will be required.
Chili Bar	2155	7/31/2007	None	Licensed prior to implementation of the Clean Water Act. NOI expected to be filed by 7/31/2002 with an Application for New License expected to be filed by 7/31/2005. 401 Certification from the SWRCB will be required.
Potter Valley	77	4/14/2022	Deemed waived by FERC in order issuing new license dated 10/4/1983.Flow release modifications deemed not to require a 401 certification by SWRCB (letter dated 6/11/1998).	NOI expected to be filed by 4/14/2017 with an Application for New License expected to be filed by 4/14/2020. 401 Certification from the SWRCB will be required.

Source: Compiled by Roy Leidy, EIP Associates, 2000

Table 4.3-4 Pacific Gas and Electric Company Hydroelectric Assets 401 Certification Status – Motherlode Regional Bundle

Asset Name	FERC License No.	Date FERC License Expires	401 Certification Status	Comments
Mokelumne River	137	11/23/1975	Certificate No. 76-23 issued by SWRCB on 9/27/1976	On Annual License. PG&E Co. applied for a certification or waiver for improvements to the facility on 15 March 1983. The Central Valley RWQCB stated that certification was not necessary (letter dated 4/3/1983). New license expected by 7/2001.
Spring Gap	2130	12/31/2004	None	Licensed prior to implementation of the Clean Water Act. NOI filed on 12/31/1999. Application for New License expected to be filed by 12/31/2002 with a license expected to be issued by about 12/2005. 401 Certification from the SWRCB will be required.
Phoenix	1061	8/31/2022	Waived pursuant to FERC Order 464	PG&E Co. requested certification or waiver on 4/14/1980. Central Valley RWQCB decided to take to action (letter dated 5/2/1980). NOI expected to be filed by 8/31/2017 with an Application for New License expected to be filed by 8/31/2020. 401 Certification from the SWRCB will be required.
Merced Falls	2467	2/28/2014	None	Licensed prior to implementation of the Clean Water Act. NOI expected to be filed by 2/28/2009 with an Application for New License expected to be filed by 2/28/2012. 401 Certification from the SWRCB will be required.

Source: Compiled by Roy Leidy, EIP Associates, 2000

Table 4.3-5 Pacific Gas and Electric Company Hydroelectric Assets 401 Certification Status – Kings Crane-Helms Regional Bundle

Asset Name	FERC License No.	Date FERC License Expires	401 Certification Status	Comments
Kings Crane-Helms Regional Bundle				
Crane Valley	1354	4/30/1989	Waived pursuant to FERC Order 464. Pacific Gas and Electric Company has proposed to amend license application which will require 401 certification.	On Annual License. PG&E Co. requested certification or waiver on 11/4/1985. No action taken by SRWCB on request. NOI was filed on 4/30/1984 and an Application for New License was filed on 4/25/1986. New license expected by 12/2002.
Kerckhoff 1 and 2	96	11/30/2022	Certificate No. 75-8 issued by SWRCB on 2/15/1975 for Kerckhoff 1 Facility. Certificate No. 79-9 issued by SWRCB on 8/17/1979 for the Kerckhoff 2 Facility.	NOI expected to be filed by 11/30/2017 with an Application for New License expected to be filed by 11/30/2020. 401 Certification from the SWRCB will be required.
Helms Pumped Storage	2735	4/30/2026	Certificate No. 75-47 issued by SWRCB on 10/1/1975	NOI expected to be filed by 4/30/2021 with an Application for New License expected to be filed by 4/30/2024. 401 Certification from the SWRCB will be required.
Haas-Kings River	1988	3/31/1985	Waived pursuant to FERC Order 464	On Annual License. PG&E Co. requested certification or waiver on 12/1/1981 and on 8/2/1983 for additions. SWRQB did not take action until 4/30 1987 when it denied certification. PG&E Co. requested FERC to find that the SWRCB had waived the certification as of 8/2/1984 due to lack of timely action. New license expected by 3/2001.
Balch 1 and 2	175	4/30/2026	Certificate No. 75-8 issued by SWRCB on 2/15/1975	NOI expected to be filed by 4/30/2021 with an Application for New License expected by 4/30/2024. 401 Certification from the SWRCB will be required.
Tule River	1333	7/31/2033	Waived pursuant to FERC Order 464	PG&E Co. requested certification or waiver on 11/14/1985. Central Valley RWQCB decided to take to action on request (letter dated 12/30/1985). NOI expected to be filed by 7/31/2028 with an Application for New License expected to be filed by 7/31/2031. 401 Certification from the SWRCB will be required.
Kern Canyon	178	4/30/2005	Certification No. 78-17 issued by SWRCB on 7/17/1978	NOI filed o 4/30/2000. Application for New License expected by 4/30/2003. License expected to be issued by about 4/2005. No request for 401 certification or waiver has been submitted.

Source: Compiled by Roy Leidy, EIP Associates, 2000

Water Quality

Section 303 of the Federal Clean Water Act (CWA) requires states to adopt water quality standards for all surface waters of the United States. Section 304(a) requires the U.S. Environmental Protection Agency (EPA) to publish water quality criteria that accurately reflect the latest scientific knowledge on the kind and extent of all effects on health and welfare that may be expected from the presence of pollutants in water. Where multiple uses exist, water quality standards must protect the most sensitive use. Water quality standards are typically numeric, although narrative criteria based upon biomonitoring methods may be employed where numerical standards cannot be established or where they are needed to supplement numerical standards. Water quality objectives for all waters in the State are established under applicable provisions of Section 303 of the Federal Clean Water Act and the State's Porter-Cologne Water Quality Act. The goals of the Porter-Cologne Act are to provide for the conservation, protection, and control of the water resources of the State. Surface water quality is the responsibility of nine Regional Water Quality Control Boards (RWQCB) and numerous water supply and wastewater management agencies, as well as city and county governments, and requires the coordinated efforts of these various entities.

Section 303(c)(2)(b) of the CWA requires states to adopt numerical water quality standards for toxic pollutants for which EPA has published water quality criteria and which reasonably could be expected to interfere with designated uses in a water body. Water quality objectives have been established for each basin in compliance with the Federal CWA and the State Porter-Cologne Water Quality Control Act. Each basin plan establishes water quality standards for the surface and ground waters of the region, and implementation measures to meet stated objectives and to protect the beneficial uses of waterways.

The SWRCB carries out its water quality protection authority through the adoption of specific *Water Quality Control Plans*. These plans establish water quality protection authority through the adoption of specific Water Quality Control Plans. The Regional Boards have adopted, and the SWRCB has approved, water quality control plans (basin plans) for each watershed basin pursuant to State law and in satisfaction of section 303 of the Clean Water Act, which requires the states to establish water quality standards.

Each basin plan designates the beneficial uses of the waters to be protected within a given region and establishes water quality standards for particular bodies of water. California water quality standards are composed of three parts: the designation of beneficial uses of water, water quality objectives to protect those uses, and implementation programs designed to achieve and maintain compliance with the water quality objectives.

Protection of the beneficial uses identified in the basin plans requires maintenance of adequate instream flows as well as effluent limitations and other limitations on discharges of pollutants from point and non-point sources. The State planning basins where Pacific Gas and Electric Company facilities are located include the Central Valley Region, which includes the Sacramento River Basin, San Joaquin River Basin, and Tulare Lake Basin, and the North Coast Region, specifically the Eel River drainage.

Central Valley-Sacramento-San Joaquin-Tulare Basins

The Sacramento, San Joaquin and Tulare River basins are bound by the crests of the Sierra Nevada on the east and the Coast Range and Klamath Mountains on the west. They extend from the California - Oregon border southward to the Kern and Los Angeles County line. The Sacramento River and San Joaquin River Basins cover about one fourth of the total area of the State and over 30 percent of the State's irrigable land. The Sacramento and San Joaquin Rivers furnish roughly 51 percent of the State's water supply. Surface water from the two drainage basins meet and form the Sacramento/San Joaquin Delta, which ultimately drains to San Francisco Bay. The Delta is a maze of river channels and diked islands covering roughly 1,150 square miles, including 78 square miles of water area. Two major water projects, the Federal Central Valley Project and the State Water Project, deliver water from the Delta to Southern California, the San Joaquin Valley, the Tulare Lake Basin, and the San Francisco Bay area, as well as within the Delta boundaries.

Sacramento River Basin. The Sacramento River Basin covers 27,210 square miles and includes the entire area drained by the Sacramento River. For planning purposes, this includes all watersheds tributary to the Sacramento River north of the Cosumnes River watershed. It also includes the closed basin of Goose Lake and drainage sub-basins of Cache and Putah Creeks.

The principal streams are the Sacramento River and its larger tributaries: Battle Creek, the Pit, Feather, Yuba, Bear, and American Rivers to the east; and Cottonwood, Stony, Cache, and Putah Creeks to the west. Important reservoirs and lakes include Shasta, Almanor, Oroville, Bullards Bar, Rollins, Spaulding, Folsom, Clear Lake, and Lake Berryessa.

San Joaquin River Basin. The San Joaquin River Basin covers 15,880 square miles and includes the entire area drained by the San Joaquin River. It includes all watersheds tributary to the San Joaquin River and the Delta south of the Sacramento River and south of the American River watershed.

The principal streams in the basin are the San Joaquin River and its larger tributaries: the Cosumnes, Mokelumne, Calaveras, Stanislaus, Tuolumne, Merced, Chowchilla, and Fresno Rivers. Major reservoirs and lakes include Pardee, New Hogan, Millerton, McClure, Don Pedro, and New Melones.

Tulare Lake Basin. The Tulare Lake Basin comprises the drainage area of the San Joaquin Valley south of the San Joaquin River. The Tulare Lake Basin is essentially a closed basin that only drains north to the San Joaquin River in years of extreme rainfall.

The Basin encompasses 16,406 square miles (approximately 10.5 million acres) including much of the upper watersheds of the Kings, Kaweah, Tule and Kern Rivers, which drain the west slope of the Sierras in Federal ownership.

North Coast Region

The North Coast Region comprises all basins draining into the Pacific Ocean from the California - Oregon State line south to the southerly boundary of the watershed of the Estero de San Antonio and Stemple Creek in Marin and Sonoma Counties. The North Coast Region is divided for planning purposes in to two natural drainage basins, the Klamath River Basin and the North Coast Basin. The only assets operated by Pacific Gas and Electric Company are located on the Eel River in the North Coast Region.

The North Coast Basin covers an area of approximately 8,560 square miles located along the north-central California Coast. The Basin is bounded by the Pacific Ocean on the west, by the Klamath River and Trinity River Basins on the north, by the Sacramento Valley, Clear Lake, Putah and Cache Creeks and the Napa River Basin on the east and by the Marin-Sonoma area on the south. Most of the Basin consists of rugged, forested coastal mountains dissected by six major river systems one of which is the Eel River. The North Coast Basin is divided into nine hydrological units with only the Pacific Gas and Electric Company Potter Valley Project located in the Eel River hydrological unit

Eel River Hydrological Unit. The only major surface water development in the Eel River hydrological unit is Lake Pillsbury, which is formed by Scott Dam, with a storage capacity of 80,700 acre-feet. This facility, in conjunction with Van Arsdale Dam and the Potter Valley tunnel provides for power generation and export of Eel River water to the Russian River Hydrological Unit.

Stormwater Runoff Water Quality Protection

The land use assumptions in Chapter 3 indicate that Watershed lands may be converted to new uses to provide residential, recreational, or commercial opportunities. New land uses would involve construction activity and a change in the amount of impervious surface, which could increase the amount of runoff containing substances that could affect water quality. Regulations and standards that address water quality protection related to new development are summarized below.

National Pollutant Discharge Elimination System Permit for Stormwater Discharges

The NPDES permit system was established in the CWA to regulate municipal and industrial stormwater discharges to surface waters of the United States. Each NPDES permit contains limits on allowable concentrations and mass emissions of pollutants contained in the discharge. The permit requires the municipal authority to evaluate the quality of its stormwater discharge and receiving waters, identify areas of pollutant loading, and implement a program of Best Management

Practices (BMPs) to control pollutant discharges to the maximum extent practicable. Sections 401 and 402 of the CWA contain general requirements regarding NPDES permits. Section 307 of the CWA describes the factors that EPA must consider in setting effluent limits for priority pollutants. It is within the existing authority of the RWQCB to issue a NPDES permit for any stormwater outfall that discharges to the waters in the region.

The CWA prohibits the discharge of pollutants to navigable waters from a point source unless authorized by a NPDES permit. The goal of the existing regulations is to improve the quality of water discharged to receiving waters to the "maximum extent practicable" through the use of Best Management Practices (BMPs). BMPs can include the development and implementation of various practices including educational measures (workshops informing public of what impacts results when household chemicals are dumped into storm drains), regulatory measures (local authority of drainage facility design), public policy measures (label storm drain inlets as to impacts of dumping on receiving waters) and structural measures (filter strips, grass swales and detention ponds).

Municipal Stormwater Discharge Permit (Phase I and Phase II Programs)

With respect to pollutants in stormwater discharges, the CWA regulates large (population 250,000 or above) and medium (population 100,000 to 250,000) municipalities, certain industrial activities, and certain construction activities to obtain permit coverage under the NDPES Phase I Program, which began in 1990. Discharges from municipal separate storm sewer systems (AMS4s@) in smaller urbanized areas have recently become regulated under Phase II program, which include small municipalities with populations of 1,000 to 100,000. The Phase II program also regulates construction activity on one to five acres. The Phase II regulations became effective February 7, 2000. All of the Project Lands are located in non-urbanized areas and are sparsely populated. Based on EPA-defined criteria, the following locations within the project are automatically designated under the Phase II program: Shasta, Butte, Yuba, Merced, and Tulare counties.

The Phase II program requires the owner or operator of a regulated small MS4 to develop, implement, and enforce a program to reduce pollutants in post-construction runoff to their MS4 from new development and development projects that result in the land disturbance of greater than or equal to one acre. The post-construction management measure requires structural and/or non-structural BMPs that would mimic pre-development quantity and quality runoff conditions from new development and redevelopment areas. Non-structural BMPs are typically cost-efficient, non-engineered management measures focused on pollution prevention and source control. Structural BMPs are typically higher cost, engineered measures that provide some treatment.

The NPDES permitting authority (in this case, the State Water Resources Control Board(SWRCB)) must issue general permits for Phase II-designated small MS4s, and operators of Phase II-regulated small MS4s must obtain permit coverage by March 2003. Fully implemented programs must be in place by the end of the first permit term, typically five years.

General Construction Activity Stormwater Permit

Stormwater runoff from construction sites requires coverage under a general NPDES permit. A new permit, which revised and updated the regional permit adopted in 1992, was issued by the SWRCB in August 1999. This permit generally applies to sites larger than five acres in size. Construction on sites one to five acres in size are regulated under the Phase II program. Landowners are responsible for obtaining and complying with the permits and may delegate specific duties to developers and contractors by mutual consent. Permit applicants are required to prepare, and retain at the construction site, a stormwater pollution prevention plan that describes the site, erosion and sediment controls, means of waste disposal, implementation of approved local plans, control of post-construction sediment and erosion control measures and maintenance responsibilities, and non-stormwater management controls. Dischargers are also required to inspect their construction sites before and after storms to identify stormwater discharge associated with construction activity and to identify and implement controls where necessary.

Streambed Alteration Agreement

Perennial and intermittent streams are under the jurisdiction of CDFG pursuant to Sections 1601 through 1603 of the Fish and Game Code (Streambed Alteration Agreements). CDFG jurisdiction over work within the stream zone includes, but is not limited to, the diversion or obstruction of the natural flow or changes in the channel, bed, or bank of any river, stream or lake. These sections of the code prohibit alterations of any streams, including intermittent and seasonal channels and many artificial channels, without a permit from CDFG. The limit of CDFG jurisdiction is, subject to the judgment of the Department, up to the 100-year flood level. This would apply to any channel modifications to meet drainage or stormwater management needs for new development.

Cloud Seeding

Water for hydroelectric generation is created through natural precipitation, including the amount of rainfall and the resulting water content of the mountain snow pack. Cloud seeding can be performed to increase precipitation from certain storm events. Pacific Gas and Electric Company engages in limited cloud seeding activities in the Motherlode and DeSabla watershed regions. In 1986, previous regulations on weather resources management were repealed. The regulations had been based on detailed permit and license requirements, which were eliminated by changes in State law at that time. The law continues to require filing Notices of Intention, some record keeping by operators, and annual or biennial reports evaluating project results.

4.3.2.3 Informal Practices

From time to time, Pacific Gas and Electric Company has conducted water management activities at some locations for enhancement of fish and wildlife, habitat, or recreational uses, in ways that are not specifically required under its FERC licenses and other regulatory entitlements. These practices are discretionary, and generally temporary or seasonal in nature. These informal practices are often conducted in cooperation with regulatory agencies, such as the CDFG, although the practices have not been incorporated into formalized agreements or regulatory entitlements. Pacific Gas and Electric Company has maintained many specific informal practices due to incentives to maintain cooperative relationships with regulatory agencies and local communities, which can lead to indirect economic benefits. Specific informal practices are discussed in the facility-specific sections below.

4.3.3 SYSTEM-WIDE SETTING

Pacific Gas and Electric Company's five Regions comprise facilities on 25 streams and rivers draining the western slopes of the Sierra Nevada and southern Cascades in central and northern California. The number and size of storage facilities varies across the five regions, but typically most of the storage volume is concentrated in two or three reservoirs, with the remaining facilities operating essentially as run-of-river. Precipitation varies widely both within and between the five Regions, from as little as 8.7 inches per year on the Kern River in the Kings Crane-Helms Region to over 74 inches per year on the Pit River in the Shasta Region. The majority of precipitation in all Regions falls during winter storms, with the wet season extending from November to March or April. Precipitation is almost exclusively rain at lower elevations, turning to snow at higher elevations. Streamflows are higher during the winter and spring, with the timing of peak flows dependent on the location and elevation of the basin and ranging from January to late April. Summer flows are significantly lower, though the relative amounts vary depending on local geology and groundwater baseflow contribution.

4.3.3.1 System-Wide Water Quality Conditions

The California State Water Resources Control Board (SWRCB) is tasked with ensuring water quality while balancing the needs of competing beneficial uses in waters of the State. The nine Regional Water Quality Control Boards (RWQCBs) develop and enforce water quality objectives and implementation plans that will best protect the beneficial uses of the State's waters. As these agencies have a mandate to protect the quality of the waters of the State, they are knowledgeable about existing water quality problems. Therefore, in compiling the environmental setting for the project, input was solicited from staff from the SWRCB and the two affected RWQCBs (the Central Valley and North Coast regions). The agency staff contacted noted that the primary compilation of existing water quality problems is the 303(d) list of impaired waters and TMDL priority schedule. This list notes, by impaired waterbody, the pollutant/stressor of concern, the source of the pollutant, and the priority for development of TMDLs. The relevant portions of the 303(d) list are described below in the water quality setting for each bundle.

With regard to the Central Valley region, the RWQCB staff did not identify any additional existing water quality problems that might be impacted by the project. The RWQCB staff noted that they do not typically review flow-related impacts in bypass reaches below hydroelectric projects. They noted that unless a facility has a waste discharge, or a dredge or fill permit is requested, the

RWQCB does not typically have any jurisdiction (CVWQCB, 2000a; CVWQCB, 2000). Staff did not foresee any specific impacts as a result of potential changes in operations at Pacific Gas and Electric Company facilities.

Staff from the North Coast RWQCB emphasized the 303(d) listings for the Upper Main Fork Eel River (Sedimentation/Siltation and Temperature) and Lake Pillsbury (Mercury) and noted that diversions from the Eel River to the Russian River are a source of colloidal turbidity in the Russian River basin, which is also listed for Sedimentation/Siltation. Although reservoir drawdown might affect turbidity, staff did not feel this was a significant concern unless there was a drastic change in operations. Considering the constraints on operations at Lake Pillsbury, RWQCB staff did not feel that this was likely. It was also noted that because discharges are made from a low level outlet at Lake Pillsbury, temperature is not likely to be affected by the project. Similar to the Central Valley Region, North Coast Region staff noted that they do not regulate very much with regard to hydroelectric operations (NCRWQCB, 2000).

None of the individuals contacted were aware of other listings or compilations of existing water quality problems within the affected region. However, the SWRCB noted that minimum flow and water temperature problems have been identified at several Pacific Gas and Electric Company facilities. Specifically, minimum flow concerns at Pit 1 and water temperature problems associated with the NFFR facilities below Butt Valley Reservoir were noted. SWRCB staff also noted several other mechanisms by which the project could adversely affect water quality. These included changes in sediment management at Pacific Gas and Electric Company reservoirs and changes in instream flow resulting from more aggressively meeting minimum instream flow targets.

With regard to sediment management, the SWRCB's concern is that a new owner may not have the same sophistication, resources, or level of concern as Pacific Gas and Electric Company for dealing with sediment in project reservoirs. Appropriate management of reservoir sediment (sluicing, flushing, dredging, etc.) is a contentious issue and one that has the potential to affect water quality downstream of most facilities. The State and Pacific Gas and Electric Company have a long history of working together to address this issue and coming to mutual agreements with regard to sediment management policies and practices. The State is concerned that a new owner may be unaware of the complexity of sedimentation management and may be more difficult to deal with to prevent adverse water quality impacts (SWRCB, 2000).

The State's second general water quality concern is that a more aggressive policy of releasing only the FERC-mandated minimum instream flows may adversely affect water quality and aquatic resources (SWRCB, 2000). Currently most of the Pacific Gas and Electric Company facilities have minimum instream flow targets for natural stream reaches below the facilities. Historic data suggests that Pacific Gas and Electric Company typically releases more flow than the absolute minimum in many of these reaches. Discussions with individuals knowledgeable about Company practices indicate that the additional releases are made as a means of assuring that minimum flow standards are never violated (i.e. as a factor of safety) (Harrison, 2000). To the extent that a new owner decides to cut back on this factor of safety, instream flows in numerous reaches could be reduced relative to the current condition, and water quality may be affected.

The East Bay Municipal Utility District (EBMUD) has raised concerns about potential water quality impacts of the project on the Mokelumne River (EBMUD, 2000). In particular, EBMUD is concerned about the timing of inflows to Pardee Reservoir and their impact on reservoir water quality. EBMUD notes that the Lower Mokelumne River is listed on the 303(d) list for copper and zinc. However, the 303(d) listing notes that the source for these pollutants is abandoned mines, which will not be affected by the project. EBMUD also raised questions about potential project related impacts on water quality as a result of upstream reservoir operations at Blue Lakes and Salt Springs Reservoir.

4.3.3.2 Known Flooding Conditions

Little information is available concerning existing flooding problems in the watersheds relevant to this project. A data request was made to the Pacific Gas and Electric Company requesting any information relating to known flood hazards downstream of the Company's facilities (PG&E Co., 2000g). In response to that data request, the Company provided documentation about flood related damages to the Drum-Spaulding project in January 1997, a description of the flow attenuation performance of Lake Almanor, and letters between Pacific Gas and Electric Company and FERC regarding the July 1998 operation of the Haas-Kings River project. Company staff further stated that Pacific Gas and Electric Company has no information about past flooding of people or structures downstream of the Company's facilities (PG&E Co., 2000f).

4.3.3.3 Known Geomorphic Problems

Assessment of geomorphic impacts of the project requires complete and accurate information about existing geomorphic problems. To our knowledge this information is not currently available. It is clear that altered flow regimes downstream of dams can affect sediment transport, including the distribution of spawning gravels, which would have geomorphic impacts. However, according to the Pacific Gas and Electric Company the facilities included in the proposed divestiture lie primarily in granitic bedded rivers, and as such the geomorphology is stable and cannot be significantly altered by project operations (PG&E Co., 2000f). The Company's response to a request for information about geomorphic problems in the stream reaches downstream of the project facilities yielded only three documents, which provided very little data about existing problems (PG&E Co., 2000g). The only reach for which site specific geomorphic data was provided was the NFFR above Cresta Dam.

4.3.4 REGIONAL AND LOCAL SETTING AND REGULATORY CONTEXT

The following sections describe water resources for each of Pacific Gas and Electric Company's FERC-licensed facilities in the five regions. Specifically, these sections describe the regional setting for each basin, regulations and policies affecting operation and water use in the basin, and the physical and operational characteristics of each bundle in the region.

4.3.4.1 Shasta Regional Bundle

The Shasta Region includes six FERC licenses covering 16 powerhouses with a combined capacity of 809.9 MW. There are four separate bundles located in the Shasta Region: Hat Creek, Pit River, Kilarc-Cow Creek, and Battle Creek (see Figure 2-18 in Chapter 2). The following sections describe water resources for each of Pacific Gas and Electric Company's FERC-licensed facilities in the Shasta Region. Specifically, these sections describe each drainage basin and the location of the facilities, describe how water is used at each facility, describe the flow of water through the different facilities, and describe water diversion and use by other beneficial users. These sections also provide a description of water conveyance systems and capacities, as well as maximum powerhouse capacity.

When applicable, the unique water use constraints, such as physical capacity constraints, storage constraints, and regulatory restrictions (e.g., instream flow release requirements) included in FERC licenses, are discussed for each facility. Schematic diagrams depict the flow of water.

Regional Setting

The Shasta Region is the most northern of Pacific Gas and Electric Company's hydropower areas. The Region encompasses 42 dams on six streams in Shasta and Tehama counties. Although it possesses the smallest reservoir capacity of the five Regions, at 159,000 acre-feet, the Shasta Region contains the largest amount of conventional hydropower capacity (810 MW). Much of the water that feeds the rivers comes from underground volcanic springs, which provide a stable and dependable supply of water. The general layout of the Shasta facilities and the major hydrographic features within this bundle are shown in Figures 2-16 and 2-17 in Chapter 2.

The northern facilities (Hat Creek, Pit River, and Pit-McCloud bundles) and the only appreciable storage reservoirs in the system lie in the Pit and McCloud River watersheds, which drain the southern Cascade Mountains to Shasta Lake. Three reservoirs in the Pit system account for essentially all of the Shasta Region's storage—Lake Britton, Lake McCloud, and Iron Canyon Reservoir. All other assets operate as run-of-river facilities. Precipitation varies widely in this part of the basin, from less than 20 inches per year at the Hat Creek Powerhouse to over 74 inches per year at the Pit #5 Powerhouse. Natural (unregulated) flow hydrographs are dominated by spring snowmelt runoff, with the highest flows occurring from late March into June. Significant year-round baseflow is provided by springs and groundwater flow in the fractured volcanic formations.

The southern facilities (Cow-Kilarc Creek and Battle Creek bundles) lie on streams draining the western slopes of Mount Lassen, tributary to the Sacramento River below Redding. All of the assets in these two bundles operate as run-of-river facilities. Annual precipitation ranges from 28 inches at the Coleman Fisheries Station to 34 inches at the Volta Powerhouse. Peak streamflows are generated both by winter rain events and spring snowmelt, resulting in relatively high flows from February into June. Year-round baseflow is derived from groundwater springs and seepage.

Portions of the Shasta Regional Bundle are underlain by the Fall River Valley groundwater basin, one of two major groundwater basins in Shasta County. The 120-square-mile Fall River Valley basin is estimated to contain approximately one million acre-feet of storage. In addition, volcanic and alluvial soils that contain groundwater in the Big Lake, McArthur, Lake Britton, Hat Creek, and Old Station areas provide most, if not all, of the water used by existing development in those areas. Unlike geographically definable groundwater basins, however, the location and amount of water found in alluvial and volcanic soils is difficult to quantify. Groundwater basins and the volcanic and alluvial soils are recharged by infiltration. Floodplains and streams that cover gravel or porous material are essential to recharge. The flat agricultural lands of the Fall River Valley is one of two significant recharge areas in Shasta County (Shasta County, 1998).

Groundwater represents 16 percent of all water diversions in the county. The county's Water Use and Wastewater Treatment Report concludes that water resources are adequate to meet existing and future needs, but the resources are not uniformly distributed, which has implications for the geographic distribution of future growth. In addition, the report indicated there is lack of precise, quantifiable data on groundwater resources, including the Fall River groundwater basin. Only a small fraction of this groundwater can be used under safe yield management. Safe yields, maximum quantities of water that can be continuously withdrawn from the groundwater basin without adverse effect, on these and other groundwater basins, are not known. However, results of the Shasta County Water Resources Master Plan indicate the valley areas in the northeastern county (i.e., Big Lake, McArthur, Burney, and Lake Britton areas) present the least constraints on future development with respect to the availability of water (Shasta County, 1998).

The quality of water in underground basins and volcanic and alluvial soils is considered generally good throughout most of Shasta County. Potential hazards to groundwater quality include concentration of nitrates and dissolved solids from agricultural practices and septic tank failures. Several small areas of elevated nitrate levels are present in eastern portions of Fall River Valley. Older valley terrace soils and certain loosely consolidated volcanic soils in eastern portions of the county severely limit the ability of soils to support septic tanks or on-site wastewater treatment systems (Shasta County, 1998).

Local Regulations and Policies

Refer to Section 4.3.2.

Bundle 1: Hat Creek

The Hat Creek Bundle consists of FERC No. 2661 (the Hat Creek 1 and 2 Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 2661.

Hat Creek 1 and 2 (FERC 2661)

The Drainage Basin and Water Sources. The Hat Creek 1 and 2 System is on Hat Creek (a tributary to the Pit River) and within the Hat Creek Basin. The Pit River originates on the western slopes of the Warner Mountains near Alturas, in Modoc County. Hat Creek begins near Hat Mountain within Lassen Volcanic National Park at an elevation of 7,695 feet. It flows in a northwesterly direction through Shasta County for nearly 40 miles before entering the Pit River. The two powerhouses (Hat Creek 1 and Hat Creek 2) are located within 5 miles of the confluence of Hat Creek with the Pit River. The basin areas contributing to the Hat Creek 1 and Hat Creek 2 Hydroelectric Generating Facilities are 400 and 431 square miles, respectively.

Water flowing into Hat Creek and its tributaries is derived primarily from groundwater that originates as precipitation captured in the extensive lava flows associated with Mount Lassen and the surrounding Hat Creek Rim. Rising River, a spring-fed tributary of Hat Creek, is the primary source of inflow into Hat Creek (PG&E Co., 1995). Groundwater is discussed in more detail below.

Hydroelectric Facilities. The asset consists of the Hat Creek 1 and Hat Creek 2 hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks) with linkages as shown in Figure 4.3-1.

Water Management. As part of the FERC license requirements, there are minimum flows that must be maintained in streams downstream of certain facilities. These are summarized below and further described in the following text.

Table 4.3-6 Minimum Releases Associated With the Hat Creek System

Facility	Time Period	Minimum Release (cfs)
Cassel Pond	Year Round	2
Baum Lake	Year Round	8

Source: PG&E Co., 1999

Water management for the Hat Creek System originates with the Hat Creek 1 Diversion Dam, also known as Cassel Pond, a small impoundment with a storage capacity of 32 acre-feet (af). Below the dam, Hat Creek 1 Canal delivers water from Cassel Pond to the powerhouse penstock via a 2,270 foot-long canal and forebay (12.5 af) system with a maximum capacity of 600 cubic-feet-per-second (cfs) (PG&E Co., 1995). The Hat Creek 1 Canal has an average annual flow of 281 cfs (USGS, 1996). The penstock has a flow capacity of 545 cfs and delivers water to the Hat Creek 1 Powerhouse (8.5 MW). Maximum gross head at the facility is 213 feet.

FERC License Article 32 requires a release of two cfs from Cassel Pond into the Hat Creek 1 bypass reach, although average daily flows in the reach are usually higher than the stipulated minimum due to accretion inflow (FERC, 1979a). The application to relicense the Hat Creek 1 and 2 System, filed September 30, 1998, proposes an increase in minimum flow release to eight cfs from Cassel Pond (PG&E Co., 1998a). Due to the lack of significant storage capacity at the Hat Creek 1 Diversion, the Hat Creek 1 Powerhouse is operated as an ROR facility, dependent on the flows available in Hat Creek. ROR facilities limit the ability of the operator to engage in certain generation strategies, such as peaking, and provision of some ancillary services.

Tailrace water from the Hat Creek 1 Powerhouse discharges into Baum Lake, the primary storage facility for the Hat Creek 2 Powerhouse (8.5 MW). Baum Lake has a storage capacity of 629 af. In addition to the inflow from the Hat Creek 1 Powerhouse, Baum Lake also receives inflow from the Hat Creek 1 bypass reach, Rock Creek, Crystal Lake, and three small springs. According to a 1978 agreement with CDFG, Pacific Gas and Electric Company generally holds Baum Lake reservoir elevations near maximum levels during the major recreation season (PG&E Co., 1978a). Water is diverted from Baum Lake into a 4,520 foot-long concrete flume with a 600 cfs-capacity that delivers water to the intake header-box, from which it drops through the penstock (580 cfs-capacity) to the Hat Creek 2 Powerhouse. Maximum gross head is 198 feet. Despite the higher storage capacity of Baum Lake, Pacific Gas and Electric Company operates the Hat Creek 2 Powerhouse as a baseload facility because the 629 af capacity of Baum Lake does not provide sufficient capacity to store water for long periods of time.

FERC License Article 32 requires a release of eight cfs from Baum Lake into the Hat Creek 2 bypass reach. Flow in the bypass reach is augmented by as much as 20-30 cfs from spring input, with 19 cfs typically emanating from a spring just downstream of Baum Lake. The Hat Creek 2 Powerhouse tailrace water merges with the bypass reach water, then flows approximately three miles down Hat Creek before entering Lake Britton on the Pit River, part of the Pit 3, 4, and 5 Facilities (FERC No. 233) (PG&E Co., 1995). In addition to minimum flow requirements for Hat Creek 1 and 2, the FERC license imposes a number of additional constraints on water management at the facilities. For example, FERC License Article 25 requires that Pacific Gas and Electric Company manage the reservoirs during flood periods such that releases from the reservoirs are no greater than the inflow (FPC, 1975a). The 1978 CDFG Agreement also stipulates a rate of change in spill release from Hat Creek 2 Dam.

Water Quality. The beneficial uses associated with Hat Creek and Baum Lake are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Hat Creek are:

- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Baum Lake has the same listed beneficial uses, with the exception of agriculture (AGR). Also, spawning (SPWN) is listed as a potential, as opposed to existing, use.

Based on available water quality data, (PG&E Co., 1995) the Hat Creek watershed can be characterized as a high quality, soft water system, with low-to-moderate concentrations of dissolved solids, pH levels ranging from neutral to alkaline, cool temperatures, moderate nutrient levels, and dissolved oxygen (DO) at or near saturation. Elevated coliform levels, likely as a result of grazing on adjacent Pacific Gas and Electric Company lands, have been detected in Baum Lake (SWRCB, 2000). Turbidity and suspended sediment concentrations are generally low; (PG&E Co., 1995). However, sedimentation in various reaches of Hat Creek has been reported (PG&E Co., 1995). The primary source(s) of sediment in Hat Creek occurs above the facilities. Sources of sediment occurring within the Hat Creek 1 and 2 area include unsurfaced roads, cattle grazing, streambank erosion, adjacent dredge spoils and fill prisms, infrequent spill events, and transport from sinkholes originating in Baum Lake (PG&E Co., 1995).

FERC License Article 19 requires Pacific Gas and Electric Company to take reasonable measures to prevent stream sedimentation and any form of water pollution, (FPC, 1975b). FERC License Article 31 requires Pacific Gas and Electric Company to consult with the RWQCB prior to using copper sulfate or other algacides in FERC-licensed waters (FPC, 1975a).

Groundwater. Groundwater seepage within the area is abundant due primarily to the existence of highly fractured lava flow bed formations (from Mount Lassen) bordering the southern and eastern boundary of the watershed (PG&E Co., 1995). Groundwater also occurs locally in shallow alluvial deposits that line creek and river canyon bottoms and, less commonly, as hot springs that originate from deep faults and fractures. Several seeps and springs contribute to the flow of Hat Creek and the two reservoirs. (PG&E Co., 1995). Rising River Springs is a major source of surface water for the area. The spring is formed when water resurfaces after percolating from river channels through subsurface deposits into a network of underlying lava tubes. Crystal Lake is another major source of water, providing continuous spring flows in excess of 100 cfs. Groundwater in the vicinity of the facilities is expected to be soft and of relatively high quality (Camp, Dresser & McKee, 1997a). All of Pacific Gas and Electric Company’s use of groundwater is passive. Facilities capture the groundwater after it surfaces and becomes part of the surface flow. Pacific Gas and Electric Company does not actively pump groundwater at the site.

Bundle 2: Pit River

The Pit River Bundle consists of FERC No. 2687 (the Pit 1 Hydroelectric Generating Facility and associated appurtenances), FERC No. 0233 (the Pit 3, 4, and 5 Hydroelectric Generating Facilities and associated appurtenances), and FERC No. 2106 (the James B. Black, Pit 6, and Pit 7 Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC licenses No. 2687, 0233, and 2106, which share overlapping boundaries. In addition, these facilities are hydrologically linked, which will be maintained under this bundling.

Pit 1 (FERC 2687)

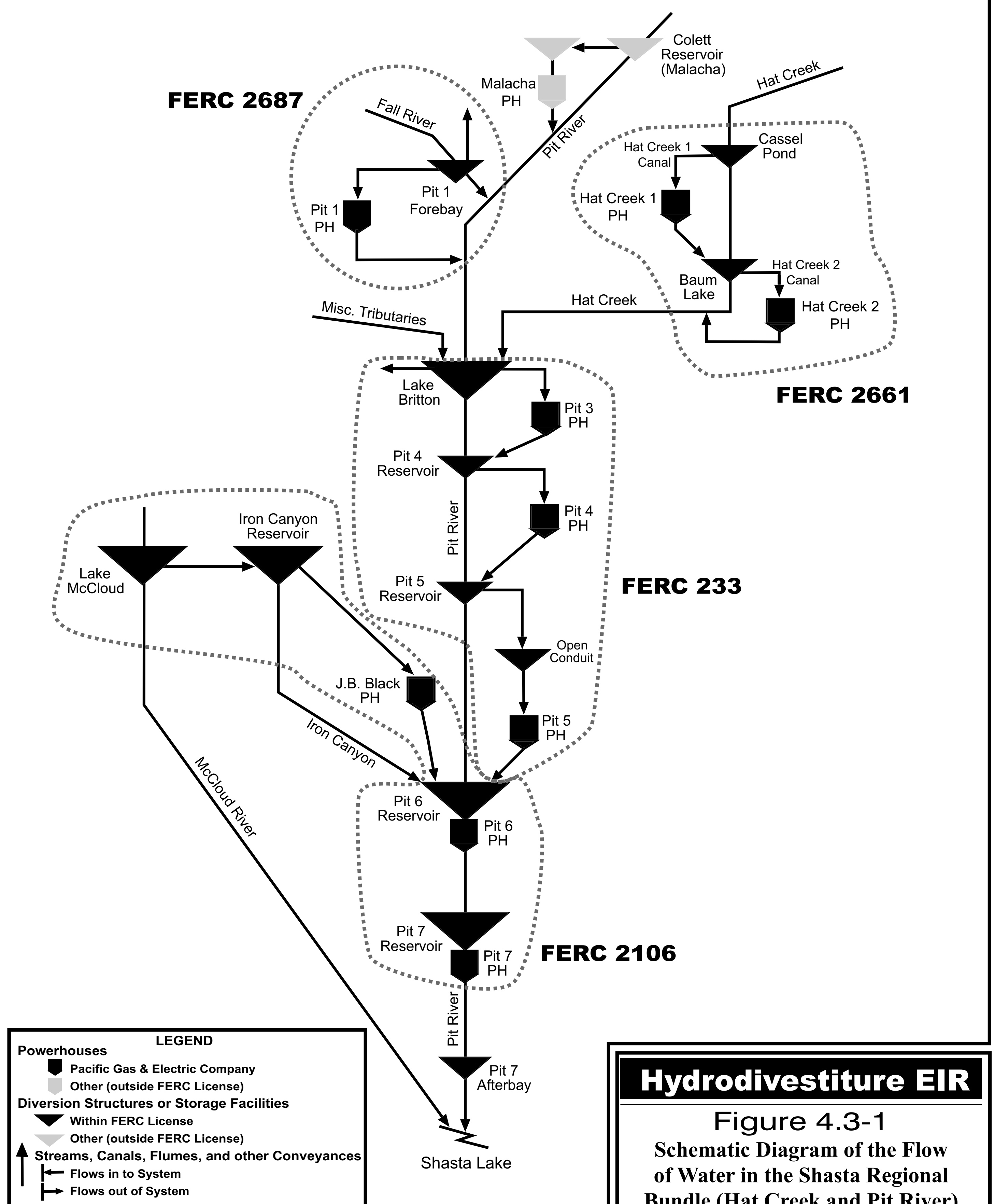
The Drainage Basin and Water Sources. The Pit 1 System is situated on the Pit River and the Fall River (a tributary to the Pit River) in Shasta County. The Pit River originates on the western slopes of the Warner Mountains near Alturas, in Modoc County. It flows southwesterly through Big Valley, Fall River Valley, Lake Britton, the Pit River Canyon, and eventually, into Lake Shasta on the Sacramento River, a distance of approximately 150 miles. Major tributaries to the Pit River include Fall River, Hat Creek, and Burney Creek.

Fall River originates from numerous large springs and spring-fed tributaries, including Spring Creek, Lava Creek, and the Tule River. The only regularly flowing surface tributary to Fall River is Bear Creek. The Tule River is a major PG&E Co., 1993). The Fall River flows in a southwesterly direction for approximately 40 miles before merging with the Pit River (PG&E Co., 1993).

All the storage and diversion facilities are located on the Fall River, but the Pit 1 Powerhouse (61 MW) is located on the Pit River, 6.7 miles downstream of the confluence of Fall and Pit Rivers (PG&E Co., 1993). The drainage area of the Fall River utilized by Pit 1 is approximately 600 square miles (PG&E Co., 1986a).

Hydroelectric Facilities. The asset consists of the Pit 1 hydroelectric generating facility, which consists of a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (conduits and penstocks) as shown in Figure 4.3-1.

Water Management. Water use and management begins with the Pit 1 Forebay, which is formed in the Fall River by a dam approximately 0.9 miles upstream of the confluence of the Pit and Fall Rivers (PG&E Co., 1993). The forebay encompasses 411 acres and has a designed usable storage capacity of 2,451 af. Water is released into the forebay at its upstream end (2.5 miles above the confluence) from the Pit 1 Diversion Dam. Water is released from the forebay into the intake canal, which travels through 1,200 feet of canal and 10,716 feet of tunnel to the headworks, from which two penstocks lead to the Pit 1 Powerhouse. The penstocks and powerhouse have a combined flow capacity of 1,900 cfs, but average annual flow for the period 1987 through 1995 was 1,154 cfs (USGS, 1997). The Pit 1 Powerhouse operates at a normal maximum gross head of 455 feet.



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Hydrodivestiture EIR

Figure 4.3-1

Schematic Diagram of the Flow of Water in the Shasta Regional Bundle (Hat Creek and Pit River)

Aspen Environmental Group

Water discharged into the tailrace enters the Pit River approximately three miles upstream of Lake Britton. Lake Britton serves as the storage reservoir for the Pit 3 Powerhouse, part of the Pit 3, 4, and 5 Facilities (FERC No. 233).

The operation of the Pit 1 System is tightly controlled by FERC license articles. In the spring, the facilities are operated, for all practical purposes, as a baseloaded facility (i.e., it is operated continuously). During this time, flow through the powerhouse is regulated to use as much of the inflow to the forebay as possible so as to avoid spilling water. FERC License Article 27 stipulates that Pacific Gas and Electric Company must manage reservoirs during flood periods such that releases are no greater than the inflow (FPC, 1970). During drier periods, the facility is operated in a peaking mode to meet system demands, despite the small capacity of the Pit 1 Forebay.

The Pit 1 System is currently in the FERC relicensing process. The specifics of the peaking operation were studied during recent relicensing proceedings. Although a new license has not yet been issued by FERC, it is expected that the new license will contain an article regulating peaking operations. At this time, Pacific Gas and Electric Company anticipates that the following conditions will be added to the new license:

> The Licensee shall provide a flow through the Pit 1 Powerhouse or release from the Pit 1 Forebay during normal operations so the total flow in the Pit River is 500 cfs or greater at the USGS gauge located downstream of the Pit 1 Powerhouse tailrace (gauge 11-3550.10, 'Pit River below Pit 1 Powerhouse near Fall River Mills'). However, during unplanned conditions such as mechanical or electrical failures, flows may temporarily drop below 500 cfs. A low flow alarm will be transmitted to the Pit 3 Powerhouse, which is staffed 24 hours a day. An operator will be dispatched to investigate and take appropriate corrective actions to restore the flows as soon as possible (PG&E Co., 1997a).

Although the new license has not yet been issued, Pacific Gas and Electric Company is currently operating the facility in a manner that meets this anticipated condition.

In addition to the reservoir level requirements for the Pit 1 System, the existing FERC license imposes a number of additional constraints on water management at the facilities. Pacific Gas and Electric Company is currently operating the facilities in a manner that meets these conditions (FPC, 1971). The FERC license for the Pit 1 Facility does not specify instream flow requirements at any points in the system. There are currently no releases made to the lower Fall River or the Pit River between the Fall River and the tailrace of the Pit 1 powerhouse (SWRCB, 2000).

Water Delivery and Domestic Use. As described in Chapter 2, Pacific Gas and Electric Company has water rights in the Pit 1 System. There are additional contracts for water delivery or supply, including an agreement to deliver water to the Fall River Mills Community Services District for use in the town and vicinity of Fall River Mills.

Water Quality. The beneficial uses associated with the Pit and Fall Rivers are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Pit River from Hat Creek to Shasta Lake are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM) (Potential)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

The Fall River has the same listed beneficial uses, with the exception of spawning (SPWN). Also, warm freshwater habitat (WARM) is an existing beneficial use on the Fall River.

Fall River and its tributary Tule River are large spring-fed systems with excellent water quality (low temperatures, low turbidity, and high DO) at their water sources. Water quality remains excellent in the narrow-channeled upper Fall River, but changes rapidly in the wide sections of the Tule River system, where temperature increases, algae blooms increase turbidity, and DO levels occasionally drop below the CVRWQCB Basin Plan objectives. Below the confluence of the Fall and Tule rivers, water quality reflects the mixing of the two systems. Warming continues, so summer mean temperatures approach 19°C just above Pit 1 Forebay; and fecal coliform levels sometimes exceed Basin Plan objectives for contact recreation (PG&E Co., 1997a). The forebay has water quality similar to the Fall River from which it receives its water. Temperatures and chlorophyll-*a* levels increase in the forebay. The forebay is the water source for the Fall River Mills Community Services District, which has reported taste and odor problems. Fall River Pond receives water from the forebay. The pond's still water and shallow depths contribute to high water temperatures and excessive growth of aquatic vegetation during the summer (PG&E Co., 1997a).

The Pit River above the confluence of Fall River is characterized by poor water quality, degraded by upstream agricultural diversions, return flows, and fecal material from livestock. Low summer flows in this segment of the river, combined with nutrient loading result in mean monthly water temperatures exceeding 22°C, frequent algae blooms, high chlorophyll-*a* concentrations, and high fecal coliforms (PG&E Co., 1997a). This reach of the Pit River upstream of the Fall River confluence is not associated with the Pit 1 area. The canyon section of the Pit River is characterized by improved water quality due to numerous springs that contribute significant flow. The clear, cool spring water reduces chlorophyll-*a* levels and associated turbidity, but most importantly, mean temperatures are reduced to less than 19°C under most hydrological and meteorological conditions (PG&E Co., 1997a).

In 1997, Pacific Gas and Electric Company prepared a Water Quality Management Plan as required by the SWRCB for the water quality certification process under section 401 of the CWA (PG&E Co., 1997a). The plan proposes specific management actions to address water quality issues in the Pit 1 Forebay, Fall River Pond, the lower Fall River, and sections of the Pit River affected by the facility. While this plan has not yet resulted in binding agreements, the SWRCB is still considering water quality conditions. These conditions may be incorporated into a new FERC license. The Fall River is included on the 1998 California CWA 303(d) TMDL list for sedimentation and siltation (USEPA, 1998). The Pit River is also listed under CWA 303(d) for nutrients, organic enrichment/low DO, and temperature due to agricultural sources (USEPA, 1998), but these problems are associated with the river above Project Lands.

Pacific Gas and Electric Company has committed to release flushing flows from the Pit 1 Dam two to three times a year to flush the vegetation out of the Fall River Pond. This requirement may also be included in the new license.

Groundwater. Because the Fall River is largely spring fed, the Pit 1 System makes passive use of groundwater. However, Pacific Gas and Electric Company does not actively pump groundwater for power production purposes.

Pit 3, 4, and 5 (FERC 233)

The Drainage Basin and Water Sources. The Pit 3, 4, and 5 System is situated on the Pit River, a major tributary to the Sacramento River, in Shasta County (PG&E Co., 1993). The Pit River originates on the western slopes of the Warner Mountains near Alturas, in Modoc County. It flows southwesterly through Big Valley, Fall River Valley, Lake Britton, the Pit River Canyon, and eventually, into Lake Shasta on the Sacramento River, a distance of approximately 150 miles. Major tributaries to the Pit River include the Fall River and Hat Creek. The drainage areas above the Pit 3, 4, and 5 Powerhouses are 4,606, 4,643, and 4,673 square miles, respectively (PG&E Co., 1996a).

Hydroelectric Facilities. The asset consists of the Pit 3, Pit 4, and Pit 5 hydroelectric generating facilities. Each consists of a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (conduits and penstocks), as shown in Figure 4.3-1.

Water Management. As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.

Table 4.3-7 Minimum Release Associated with the Pit 3, 4, 5 System

Facility	Time Period	Minimum Release (cfs)
Lake Britton	Year Round	150
Pit 4 Reservoir	Year Round	150
Pit 5 Reservoir	Year Round	120

Source: PG&E Co., 1999

Water management and use for the system, which is downstream of the Pit 1 and Hat Creek Facilities, begins in Lake Britton. Lake Britton receives water from the Pit River, Hat Creek, Burney Creek and smaller tributaries. Lake Britton, with a designed storage capacity of 40,600 af, is the forebay for the Pit 3 Powerhouse (70.0 MW) and serves as the primary storage reservoir. The size of this reservoir provides the operating flexibility needed to operate the downstream powerhouses in peaking mode, allowing Pacific Gas and Electric Company to respond in a coordinated manner to system energy requirements as determined by the energy market. During periods of seasonal high flows, however, all three powerhouses are operated as baseload facilities to pass the high flows downstream to the larger Shasta Reservoir, which is owned and operated by the U.S. Bureau of Reclamation (USBR) for flood control and storage.

Water management in Lake Britton is performed to best maximize the benefits of power generation, with considerations given for local recreation and protection of the endangered southern bald eagle (FERC, 1992a). This management must, however, be performed within the constraints of FERC license articles and contractual agreements. In 1988 flashboards were replaced with inflatable rubber crest gates. This allows the reservoir to store up to a maximum water surface elevation of 2,738.5 feet, increasing the net head on the Pit 3 Powerhouse. Normally, from Monday through Friday, the reservoir is drawn down to provide peaking power and maximum economic utilization of the facility’s capability.

During the remainder of the year, the facility is operated daily for peak loads with a similar periodic cycling of the reservoir on a weekly basis. During periods of actual or evident potential spill (winter and spring), the system is operated at full load. Operation below reservoir elevation 2,724.5 feet seldom occurs and is programmed to minimize the effect on recreational use of FERC-licensed waters (PG&E Co., 1970). A 1998 FERC Order also requires that Pacific Gas and Electric Company release water from Lake Britton for bald eagle habitat and aquatic resource protection. Under this order, Pacific Gas and Electric Company must release 150 cfs from Lake Britton into the six-mile-long Pit 3 bypass reach year-round (FERC, 1998a).

Because Lake Britton is also used for recreational boating, Pacific Gas and Electric Company maintains a high lake level in the summer, although this is not required by the FERC license. The license does specify that the lake level may fluctuate in elevation by thirteen feet.

Water is released from Lake Britton into the 3,315 cfs-capacity Pit 3 Tunnel, which conveys it approximately four miles to a valve house, and then to the 3,135 cfs-capacity Pit 3 Powerhouse. Water discharged from the Pit 3 Powerhouse enters the Pit River and is impounded by the 1,970-af Pit 4 Reservoir. The Pit 3 Powerhouse operates at a normal maximum gross head of 315 feet.

The Pit 4 Reservoir serves as the forebay for the Pit 4 Powerhouse (95.0 MW) (PG&E Co., 1997b). Just upstream of the dam, an intake structure transfers water to a pressurized tunnel with a normal maximum capacity of 3,700 cfs. The tunnel is 4.1 miles in length and cuts through Chalk Mountain. At its terminus, the water flows into two penstocks approximately 820 feet in length that lead to the 3,700 cfs-capacity powerhouse. Water discharged from the Pit 4 Powerhouse (95.0 MW) enters the Pit River and is impounded by the Pit 5 Intake Reservoir. The Pit 4 Powerhouse operates at a normal maximum gross head of 382 feet.

The 1987 FERC Order also requires a 150-cfs release from Pit 4 Reservoir into the 7.5-mile-long bypass reach (FERC, 1987a) which is often supplemented by spilled water during high flow periods. Average annual flow in the bypass reach was 499 cfs between 1955-1996 (USGS, 1997).

Two reservoirs, connected in series, provide storage for the Pit 5 Powerhouse (160.0 MW): the Pit 5 Intake Reservoir and the Pit 5 Open Conduit Reservoir. The Pit 5 Intake Reservoir has a design storage capacity of 314 af, and provides water to Tunnel 1. Tunnel 1 provides water to Pit 5 Open Conduit Reservoir, which has a design capacity of 1,044 af. (USGS, 1997). Pit 5 Open Conduit Reservoir serves as a 3,124 foot-long conduit supplying water to Tunnel 2, via an intake structure. Tunnel 2 provides water to the valve house, which provides water to four steel penstocks connecting to the powerhouse turbines. The normal maximum flow capacity of the Pit 5 Powerhouse is 3,580 cfs. It operates at a normal maximum gross head of 615 feet, generating up to 160 MW. Water discharged from the powerhouse enters the Pit River and is impounded in the Pit 6 Reservoir, part of the McCloud-Pit System (FERC No. 2106).

The storage facilities associated with Pit 4 and 5 are operated primarily as regulation reservoirs. The water surfaces of these reservoirs fluctuate on daily and weekly cycles as do the forebays for the Pit 4 and Pit 5 Powerhouses. Pit 4 and 5 Reservoirs and the Pit River bypass reaches between Pit 3 Dam and Pit 5 Powerhouse (Pit 3, Pit 4 and Pit 5 reaches) have been identified as important eagle foraging areas. (CDFG, 1986). The operation of the Pit 3, 4 and 5 System has the potential to affect the quality of bald eagle foraging habitat in these areas.

The 1987 FERC Order also sets a minimum flow of 120 cfs, measured below Nelson Creek, in the Pit 5 bypass reach (FERC, 1987a). Average annual flow through the bypass reach between 1944 and 1996 was 569 cfs, resulting from spill at the facilities during wet periods and tributary inflow (USGS, 1997).

Water Quality. The beneficial uses associated with the Pit River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality

Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Pit River from Hat Creek to Shasta Lake are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM) (Potential)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Water quality in the area is generally high and supports rainbow trout fisheries in many areas (e.g., below Lake Britton). The Pit 3, 4, and 5 System has experienced seasonal fluctuations in turbidity and suspended solids (CDFG, 1986). While this problem is not a result of facility operation, it has been raised as an issue of concern for fisheries and bald eagle foraging. Depending upon the outcome of ongoing bald eagle and fish resource monitoring, Pacific Gas and Electric Company could be required to change operations to minimize the adverse affect of these turbidity problems.

FERC License Article 19 requires Pacific Gas and Electric Company to take reasonable measures to prevent stream sedimentation and any form of water pollution (FPC, 1975c).

Groundwater. Little is known about groundwater in the area. However, because of the extensive network of springs and seeps that exists in the region, it is likely that surface water used by the facilities arises largely from local groundwater seepage. However, Pacific Gas and Electric Company does not actively pump groundwater for power production purposes.

McCloud-Pit (FERC 2106)

The Drainage Basin and Water Sources. The major facilities of the McCloud-Pit System are situated in the Pit River basin, although a storage reservoir on the McCloud River in the McCloud Basin diverts water into the Pit River. The Pit River originates on the western slopes of the Warner Mountains near Alturas, in Modoc County. It flows southwesterly through Big Valley, Fall River Valley, Lake Britton, the Pit River Canyon, and eventually, into Lake Shasta on the Sacramento River, a distance of approximately 150 miles. The McCloud River originates in the Cascade Range east of Mount Shasta and drains a total of 670 square miles in Modoc and Shasta Counties. The perpetual snowfields and glaciers of Mount Shasta are the principal sources of flow for the McCloud River (PG&E Co., 1985a).

Hydroelectric Facilities. The asset consists of the James B. Black, Pit 6, and Pit 7 hydroelectric generating facilities. Each is composed of a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (dams and penstocks), as shown in Figure 4.3-1.

Water Management. As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.

Table 4.3-8 Minimum Release Associated with McCloud – Pit System

Facility	Time Period	Minimum Release (cfs)
Lake McCloud	May-November	50*
	December-April	40*
Iron Canyon Reservoir	Year Round	3
Pit 7 Reservoir	Year Round	150

*Plus additional to meet 170-210 cfs minimum at specified times.

Source: PG&E Co., 1999

The McCloud-Pit System consist of three powerhouses and four regulating reservoirs with a combined design storage capacity of 109,307 af. All three powerhouses are operated as peaking units, in coordination with the Pacific Gas and Electric Company powerhouses upstream on the Pit River, allowing Pacific Gas and Electric Company to respond in a coordinated manner to system energy requirements as determined by the energy market. During periods of seasonal high flows, however, powerhouses on the river are operated as baseload facilities to pass the high flows downstream to the larger Shasta Reservoir, which is owned and operated by the USBR for flood control and storage.

The James B. Black Powerhouse (172.0 MW) is located on the Pit River just upstream of the Pit 5 Powerhouse. Water storage for the powerhouse begins at Lake McCloud, with 35,234 af of storage, on the McCloud River. Water is released from Lake McCloud into the 1,450-cfs-capacity McCloud Tunnel, where it transits 7.1 miles to Iron Canyon Reservoir, lying near the Pit River basin. The mean annual flow in the tunnel between 1966 and 1996 was 857 cfs.

Minimum flow requirements were set by a 1960 agreement with the CDFG (PG&E Co., 1960), included in FERC License Article 31 (FPC, 1961), and further amended by a 1989 FERC Order (FERC, 1989). FERC License Article 31 requires a minimum release from Lake McCloud to the McCloud River of 50 cfs from May through November and 40 cfs from December through April. It also stipulates that Pacific Gas and Electric Company release additional water above the 40/50 cfs minimum, at certain times, to meet minimum flows of 170 cfs to 210 cfs (depending on the time of year and water year type) at the Ah-Di-Na gaging station 3.9 miles downstream of McCloud Dam. The mean annual flow at the gage between 1965-1996 was 315 cfs, resulting from spill at the facilities during wet periods and tributary inflow.

Iron Canyon Reservoir, a 24,197 af-capacity reservoir located on Iron Canyon Creek, serves as the regulating forebay for the James B. Black Powerhouse. Water is released from the reservoir into the 2,000-cfs-capacity Iron Canyon Tunnel that carries it 2.9 miles to a penstock leading to the James B. Black Powerhouse. Average annual flow to the powerhouse for the period 1966-1996 was

903 cfs (USGS, 1997). The James B. Black Powerhouse operates at a normal maximum gross head of 1,226 feet.

Pacific Gas and Electric Company does not have spill rights at Iron Canyon Reservoir, requiring Pacific Gas and Electric Company to carefully manage flows in and out of the reservoir. In addition, a 1964 MOU with the USFS limits the maximum operating water level in Iron Canyon Reservoir to provide capacity for storm water storage and minimize possible spillage into and scouring of Bluejay Creek (PG&E Co., 1964). A revised recreation plan modified the maximum level of Iron Canyon Reservoir to 2,665 feet msl (a one-foot increase); however, under normal operating conditions this level is never reached (PG&E Co., 1972a).

During the fishing season, Pacific Gas and Electric Company maintains the level of the Iron Canyon Reservoir to make the boat ramp operational. Pacific Gas and Electric Company conducts this practice in a manner to avoid reservoir spills. This practice is conducted informally, and is not specifically required under its FERC license or other regulatory requirements.

FERC License Article 31 requires a release of three cfs below the Iron Canyon Dam. Tailrace water from the James B. Black Powerhouse flows into the Pit River, just upstream of the Pit 5 tailrace (from the Pit 3, 4, and 5 Facilities), and enters the Pit 6 Reservoir.

The Pit 6 Reservoir, formed by Pit 6 Dam, has a design capacity of 15,605 af. Two steel penstocks with a normal maximum capacity of 6,470 cfs, extend from the dam to the Pit 6 Powerhouse (80 MW). The powerhouse operates at a normal maximum gross head of 155 feet. Water discharged from the powerhouse immediately enters the Pit 7 Reservoir. The Pit 7 facilities are similar to those of Pit 6. Water is released from the 34,302-af Pit 7 Reservoir into two steel penstocks with a normal maximum capacity of 7,440 cfs, leading to the Pit 7 Powerhouse (112 MW). The powerhouse operates at a normal maximum gross head of 205 feet. Tailrace water is discharged to Pit 7 Afterbay, located on the Pit River to reduce flow energies prior to entering Shasta Lake.

FERC License Article 34 stipulates that Pacific Gas and Electric Company must operate the Pit 6 and Pit 7 Reservoirs to maintain minimum pools of not less than 1,000 af, except during maintenance (FPC, 1961). FERC License Article 47 requires a minimum flow release of 150 cfs below the Pit 7 Reservoir, although daily flows are generally in excess of this minimum (FPC 1962). Average annual flow in the river just downstream of the dam for the period 1966-1996 was 4,875 cfs (USGS, 1997).

Water Quality. The beneficial uses associated with the Pit and McCloud Rivers are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standard s. Beneficial uses of the McCloud River are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

In addition to these uses, the Pit River from Hat Creek to Shasta Lake also supports agricultural supply (AGR) and potential for warm freshwater habitat (WARM).

Water quality in the McCloud River watershed is reported to be naturally variable from excellent to highly turbid (CDFG 1990). Much of the turbidity is generated by glacial mud and volcanic ash contributed by Mount Shasta's Konwakiton Glacier via Mud Creek, a tributary to the McCloud River just above McCloud Reservoir. The McCloud River runs through a region composed of various volcanic formations, and springs fed by the percolation of water through these formations feed the river and give it a relatively stable flow relative to other Northern California rivers (PG&E Co., 1985).

FERC License Article 50 requires that Pacific Gas and Electric Company prevent the discharge of silt and debris into the McCloud and Pit Rivers, and prevent the loss of gravel from the McCloud River channel downstream of the diversion dam (FPC, 1965a). FERC License Article 45 requires Pacific Gas and Electric Company to provide structures for the control of temperatures below the McCloud diversion dam in the interest of fish life, remove barriers to fish in the McCloud River which would occur because of reduced flows, and construct a barrier to the migration of rough fish from Shasta Lake into the McCloud River, as may be prescribed hereafter by the Commission upon the recommendation of CDFG or the Secretary of the Interior, after notice and opportunity for hearing.

Pacific Gas and Electric Company currently operates McCloud Reservoir to minimize releases of highly turbid and warm water into the McCloud River. The McCloud River is naturally turbid; the selective operation of sluice gates and the middle and lower freshwater intakes has the potential to reduce turbidity and water temperature. These measures enhance the water quality of downstream reaches of the river while maintaining effective reservoir operation.

Groundwater. Because the McCloud River runs through a volcanic region that is fed by springs, the facilities make passive use of groundwater after it joins the surface flow of the McCloud River. Pacific Gas and Electric Company, however, does not actively pump groundwater for power generation purposes.

Bundle 3: Kilarc-Cow Creek

The Kilarc-Cow Creek Bundle consists of FERC No. 0606 (the Kilarc and Cow Creek Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 0606.

Kilarc-Cow Creek (FERC 606)

The Drainage Basin and Water Sources. The Kilarc-Cow Creek System lies in the Cow Creek basin within Shasta County. Located in the Cascade Mountain Range, Cow Creek is a direct tributary to the Sacramento River, entering downstream of Lake Shasta. The drainage areas contributing to the Kilarc and Cow Creek hydroelectric generating facilities are 28.8 and 71.6 square miles, respectively (PG&E Co., 1996b). The Kilarc facility lies in the North Fork Cow Creek (also referred to as Old Cow Creek) Sub-basin while the Cow Creek facility lies in the South Fork Cow Creek (SFCC) Sub-basin.

Hydroelectric Facilities. The asset consists of the Kilarc and Cow Creek hydroelectric generating facilities. Each facility consists of a powerhouse, diversion dams, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-2.

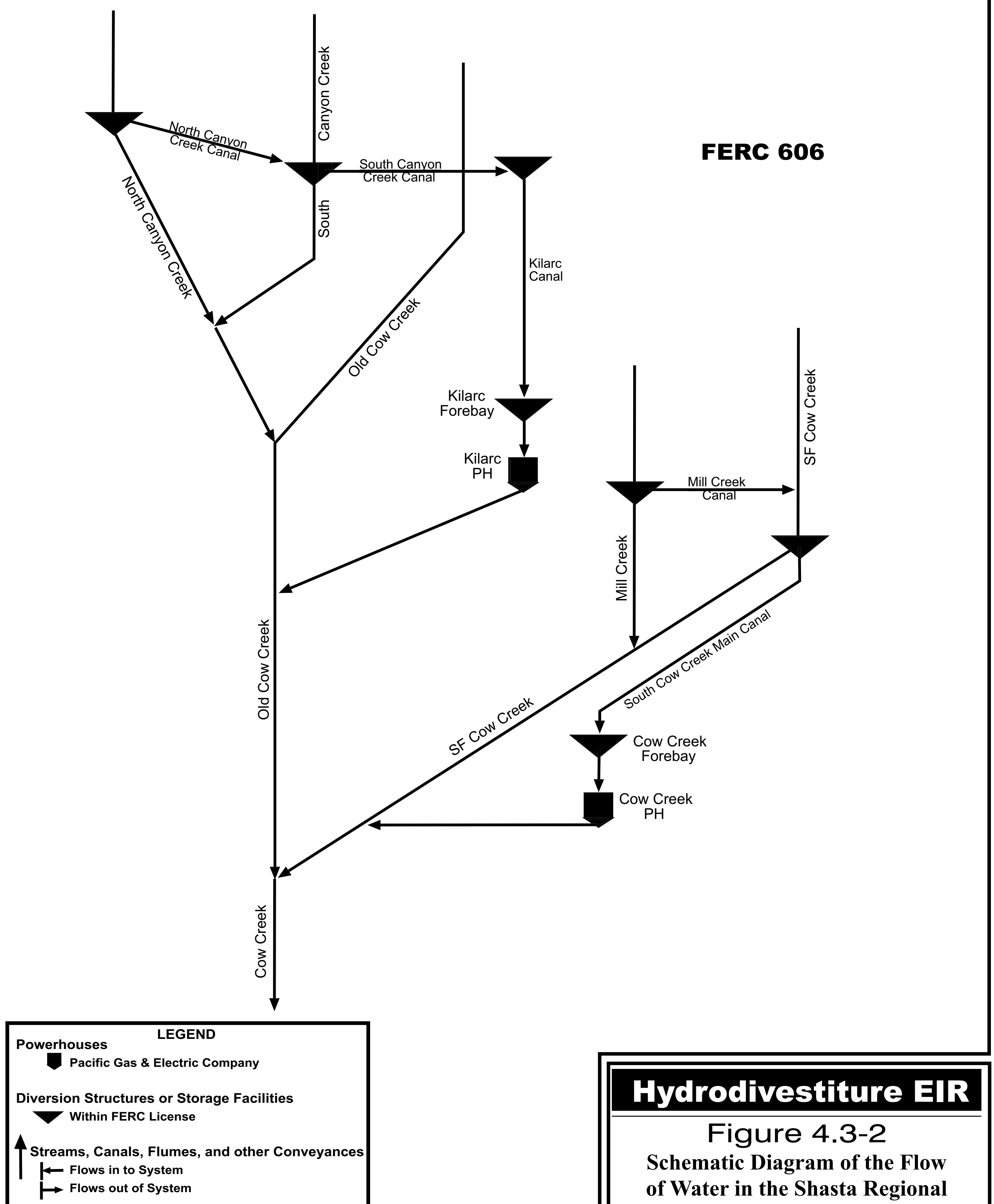
Water Management. As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.

Table 4.3-9 Minimum Release Associated with the Kilarc – Cow Creek System

Facility	Time Period	Minimum Release (cfs)
Kilarc Diversion Dam	Year Round	2
South Cow Creek Diversion Dam	Year Round	4 (normal years) 2 (dry years)

Source: PG&E Co., 1999

The headwaters of Old Cow Creek originate near Crater Peak (elev. 8,677 feet) within Lassen National Forest in Shasta County. The Kilarc facility begins with a 1.5-cfs water diversion from North Fork Canyon Creek into North Canyon Creek Canal, which discharges to South Canyon Creek. The water is then diverted into South Canyon Creek Canal, where it is conveyed approximately 0.9 miles to the 3.5-mile-long Kilarc Main Canal, with a maximum capacity of 55 cfs. The Kilarc Main Canal receives its primary source of water from Old Cow Creek via the Kilarc Diversion Dam. A minimum release of two cfs is made into Old Cow Creek below Kilarc Diversion Dam in compliance with FERC License Article 43 (FERC, 1980a). The terminus of the Kilarc Canal is the Kilarc Forebay, which has a designed storage capacity of 30.4 af. At the Kilarc Forebay, water is conveyed through a steel penstock approximately 4,800 feet long into two turbines at Kilarc Powerhouse (3.2 MW) which has a capacity of 43 cfs. The powerhouse operates



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Hydrodivestiture EIR

Figure 4.3-2

Schematic Diagram of the Flow of Water in the Shasta Regional Bundle (Kilarc-Cow Creek)

Aspen Environmental Group

at a normal maximum gross head of 1,192 feet. Tailrace water discharges into Old Cow Creek. Because Kilarc Powerhouse has little upstream storage and relies on available stream flow, it is operated as a ROR facility.

The headwaters for the SFCC originate near Latour Butte (elev. 6,732 feet), within Lassen National Forest in Shasta County. The Cow Creek facility begins with the diversion of water from Mill

Creek (a tributary of the SFCC) into Mill Creek Canal. Mill Creek Canal delivers up to five cfs to the SFCC immediately above the South Cow Creek Diversion Dam. The diversion dam diverts water into the South Cow Creek Main Canal, which has a maximum capacity of 54 cfs. Water is conveyed 2.1 miles in the South Cow Creek Main Canal before entering the Cow Creek Forebay. The Cow Creek Forebay has a design storage capacity of 5.4 af. A penstock conveys water from the forebay to the Cow Creek Powerhouse (1.8 MW) which has a capacity of 50 cfs. The powerhouse operates at a normal maximum gross head of 715 feet. Water that passes through the powerhouse is discharged into Cow Creek. Cow Creek Powerhouse operates as an ROR facility, relying solely on available stream flow.

FERC License Article 43 requires a minimum flow release of four cfs to SFCC below the South Cow Creek Diversion Dam in normal water years; these flows can be reduced to two cfs during dry years (FERC 1980a).

Water Quality. The beneficial uses associated with Cow Creek are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Cow Creek are:

- Municipal and Domestic Supply (MUN) - Potential
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Anadromous Chinook salmon, steelhead trout, and resident salmonids occur and spawn within the FERC-licensed area, which may indicate that water quality is good. FERC License Article 19 requires Pacific Gas and Electric Company to take measures to prevent stream sedimentation and any other form of water pollution (FERC 1975a). Little Cow Creek, which flows into Cow Creek, is listed under California CWA 303(d) for cadmium, copper, and zinc from abandoned mines (USEPA, 1998).

Groundwater. Old Cow Creek and SFCC converge to form Cow Creek (PG&E Co., 1975). Several springs occur within the vicinity of the facilities (Camp, Dresser & McKee, 1997a), and Cow Creek receives a large portion of its surface flow from them (Archaeological/Historical 1989). Groundwater seepage within the Kilarc-Cow Creek system area can occur from bedrock seeps and springs. Groundwater can also occur locally in shallow alluvial deposits that line creek and river canyon bottoms, and less commonly as hot springs that originate from deep faults and fractures in the batholithic rocks (Camp Dresser & McKee, 1997b). Pacific Gas and Electric Company does not actively pump groundwater for power generation purposes.

Bundle 4: Battle Creek

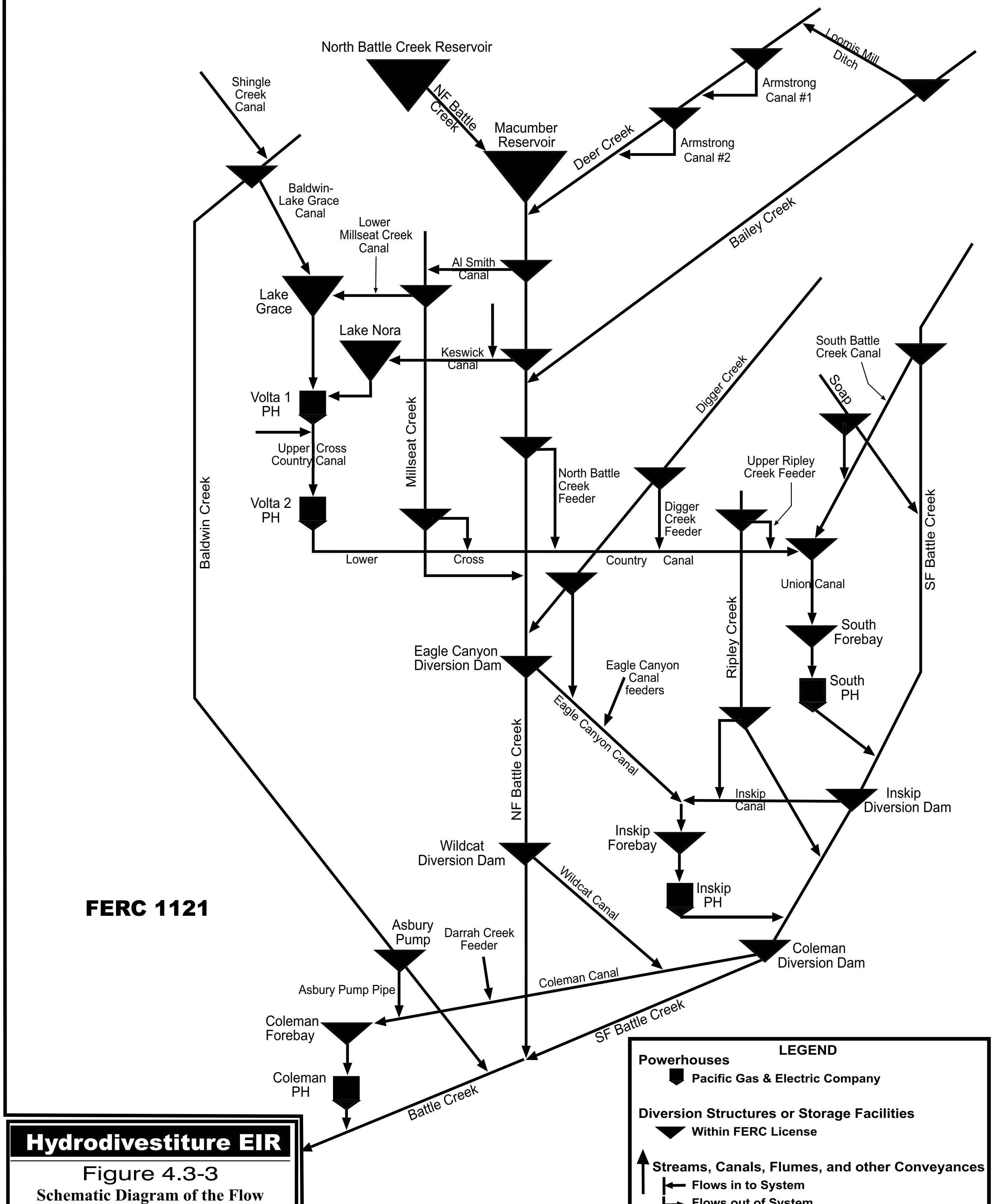
The Battle Creek Bundle consists of FERC No. 1121 (the Volta 1 and 2, South, Inskip, and Coleman Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 1121.

Battle Creek (FERC 1121)

The Drainage Basin and Water Sources. Battle Creek drains the western slopes of Mount Lassen, which lies in the southernmost range of the Cascade Mountains and is a direct tributary to the Sacramento River, entering downstream of Lake Shasta. The Battle Creek System, located in Shasta and Tehama Counties, is composed of five hydroelectric generating facilities that lie within different sub-basins of the Battle Creek basin. The Volta 1 and Volta 2 Powerhouses are situated on the North Fork Battle Creek (NFBC) Sub-basin. These facilities utilize water from NFBC Sub-basin but also make use of water transferred from Ash Creek and Baldwin Creek. The South and Inskip facilities are situated on the South Fork Battle Creek (SFBC) and utilize water from a 88.3-square-mile drainage within the sub-basin as well as water transferred from the NFBC. Finally, the Coleman Powerhouse is situated at the base of the Battle Creek Basin below the confluence of the North and South Forks, utilizing water from a 332-square-mile drainage area, including water from the South Fork of Battle Creek below Inskip Powerhouse (PG&E Co., 1996b).

Hydroelectric Facilities. The asset consists of the Volta 1, Volta 2, South, Inskip, and Coleman hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-3.

Water Management. As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.



Hydrodivestiture EIR

Figure 4.3-3
Schematic Diagram of the Flow of Water in the Shasta Regional Bundle (Battle Creek)

Aspen Environmental Group

Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Table 4.3-10 Minimum Releases Associated with the Battle Creek System

Facility	Time Period	Minimum Release (cfs)
North Battle Creek Reservoir	Year Round	0.3, not to exceed 40
Macumber Reservoir	April 1 – September 10	0.3
Al Smith Diversion Dam	Year Round	3
Keswick Canal Diversion Dam	Year Round	3
NFBC Feeder Diversion Dam	Year Round	3
South Battle Creek Diversion Dam	Year Round	5
Inskip Diversion Dam	Year Round	5
Eagle Canyon Diversion Dam	Year Round	3
Coleman Diversion Dam	Year Round	5
Wildcat Diversion	Year Round	3
Coleman Forebay/Powerhouse	Year Round	150

Source: PG&E Co., 1999

Water management originates at North Battle Creek Reservoir, with a storage capacity of 1,090 af. Approximately seven miles downstream of the North Battle Creek Reservoir is the second largest reservoir, Macumber Reservoir, with a usable storage capacity of 430 af. The integrated storage in these two reservoirs provides water for all the powerhouses in the Battle Creek system during certain periods of the year.

Water discharged from the two reservoirs flows down the NFBC Sub-basin where it is used within the sub-basin for power production. Downstream of Macumber Reservoir, NFBC is joined by Deer Creek, which has been augmented by a diversion from Bailey Creek flowing through Loomis Mill Ditch, then into Armstrong Canal No. 1, and finally Armstrong Canal No. 2. Armstrong Canal No. 2 can deliver up to about 14 cfs to Deer Creek.

FERC License Article 33 requires that North Battle Creek Reservoir be maintained at or above 1,039-af capacity during the annual recreation season from June 1 to September 10 (FERC 1997b). In addition, the article stipulates that an elevation at or above a minimum pool of 75 af (elevation 5,544 feet msl) be maintained from September 11 through May 31 (except for purposes of maintaining stream flow releases, maintenance and repairs, or emergencies) and controlled releases cannot exceed 40 cfs (FERC 1976). An hourly ramping rate required by FERC License Article 33 further constrains releases from the reservoir. During upramping, flow in the stream may be doubled each hour, while during downramping, the flow may be reduced by half each hour, to a minimum of five cfs. The license article also specifies a minimum flow release of 0.3 cfs from April 1 to October 31.

FERC License Article 33 specifies that Macumber Reservoir also must be full to provide for recreational uses between April 1 and September 10 and must also make a minimum release of 0.3 cfs during that same period. Pacific Gas and Electric Company has an informal agreement with the

CDFG not to lower the Macumber Reservoir below 12 feet at any time, to avoid potential adverse impacts to fish.

Below Macumber Reservoir, water is first used for power production at the Volta 1 and Volta 2 facilities. For the Volta 1 and Volta 2 Powerhouses, the NFBC is diverted at two locations: (1) into Al Smith Canal with a capacity of 55 cfs, and (2) into the Keswick Canal which also has a capacity of 55 cfs. The Al Smith Canal conveys the water to Millseat Creek, where it flows down Millseat Creek, and is then diverted into the Lower Millseat Creek Canal, which has a capacity of 75 cfs. It is then conveyed to Lake Grace, with a gross storage capacity of 46.5 af (PG&E Co., 1969), the larger of two forebays for the Volta 1 Powerhouse (9 MW) (PG&E Co., 1969). Additional water is diverted into Lake Grace from Shingle Creek Diversion through the Grace-Baldwin Canal at a maximum rate of four cfs.

FERC License Article 33 requires a minimum release of three cfs year round from the Al Smith Diversion into the NFBC for fish habitat.

The Keswick Canal Diversion is the second diversion on NFBC (the first is the Al Smith Diversion discussed above) and diverts a maximum of 55 cfs of water into the Keswick Canal. The canal then conveys the water four miles to the 14.9-af Lake Nora, the second forebay to Volta 1 Powerhouse. Keswick Canal also receives natural inflow from Berry Creek at 1.5 cfs.

FERC License Article 33 also requires a minimum flow release of 3 cfs year round below Keswick Canal Diversion into the NFBC for fish habitat.

Water is conveyed from the two forebays, Lake Grace and Lake Nora, through separate penstocks, each with a capacity of 55 cfs, into the 115-cfs-capacity Volta 1 Powerhouse (9 MW). The powerhouse operates at a normal maximum gross head of 1,264 (Powerhouse Physical Data Sheets, 1998) feet on one nozzle and 1,216 feet on the other nozzle. The tailrace water enters the Upper Cross Country Canal, which has a capacity of 140 cfs. The Upper Cross Country Canal conveys the water approximately 0.5 miles to the Volta 2 header box, where it drops through the 121 cfs design capacity penstock into the 115-cfs-capacity Volta 2 Powerhouse (0.9 MW). The powerhouse operates at a normal maximum gross head of 125 feet. Volta 1 and 2 Powerhouses are operated as ROR facilities, with their energy output determined by the amount of stream flow available. Flows fluctuate during storm periods and snowmelt but are generally constant during late summer and fall. Due to the unique aquifer characteristics yielding large volumes of groundwater, this watershed is very drought resistant.

The Volta 2 Powerhouse tailrace water, combined with additional water diverted at the NFBC feeder (capacity 50 cfs), is then transported into the SFBC Sub-basin via the Lower Cross Country Canal, an interbasin canal with a capacity of 130 cfs, for use in the South, Inskip and Coleman facilities.

FERC License Article 33 requires a minimum flow release of three cfs year round from the NFBC feeder diversion to the NFBC to benefit fish habitat.

As it transfers water from NFBC to SFBC, the Lower Cross Country Canal receives up to ten cfs of additional water diverted from Millseat Creek, up to 15 cfs from the Bramlett-Bristol-Benton Canal (a.k.a. Digger Creek feeder), and all the water from Upper and Lower Ripley Creek feeders (ordinarily two to six cfs). The Lower Cross Country Canal joins the 90-cfs-capacity South Battle Creek Canal, which carries water diverted from SFBC Diversion, and all available natural flows from Soap Creek, to Union Canal. The Union Canal, with a maximum capacity of 250 cfs, conveys the water from the two canals to 190 cfs-capacity South Powerhouse (7.0 MW) via South Forebay. The powerhouse operates at a normal maximum gross head of 516 feet.

FERC License Article 33 requires a minimum flow release of five cfs year round to the SFBC at the South Battle Creek Canal diversion to benefit fish habitat.

Water discharged from South Powerhouse enters a channel that conveys the water back into SFBC. South Powerhouse is operated as an ROR facility because there is little storage and its energy output is determined by the amount of available stream flow.

The Inskip Powerhouse (8 MW) makes use of water from two sources: (1) tailrace flows from the South Powerhouse diverted from SFBC into the 220-cfs-capacity Inskip Canal and (2) water transferred into SFBC from a second interbasin canal, the Eagle Canyon Canal. Eagle Canyon Canal and the Inskip canal join at a header box just upstream of the Inskip Forebay. The powerhouse operates at a normal maximum gross head of 383 feet. The Eagle Canyon Canal, with a capacity of 90 cfs, brings water 1.67 miles from the NFBC.

FERC License Article 33 requires a minimum release from the Inskip Diversion Dam into SFBC of five cfs year round. In addition, the article requires a minimum flow of three cfs to be released to NFBC below the Eagle Canyon Diversion Dam. However, an interim 1998 agreement between Pacific Gas and Electric Company, the USBR, and other parties (the Battle Creek Agreement), which is an initial step in implementing the long term Battle Creek Salmon and Steelhead Project discussed below, specifies a larger release of 30 cfs, plus or minus five cfs, for fisheries habitat purposes. The larger release provides a greater volume of colder water, which has been identified as benefiting the habitat as colder temperatures are critical for successful salmon spawning, rearing, and adult over-summering activities (U.S. Bureau of Reclamation, 1998). After Eagle Canyon Canal and the Inskip Canal merge, the water flows into the Inskip Forebay where it is delivered to the 270-cfs capacity Inskip Powerhouse via a penstock. Inskip Powerhouse also operates as an ROR facility, relying on available stream flow to produce its energy. The water discharged from the Inskip Powerhouse enters a tailrace channel that flows into SFBC. The water is diverted from SFBC in the Coleman Canal approximately 1/4 mile downstream of Inskip Powerhouse at the Coleman Diversion Dam.

Coleman Diversion Dam on the SFBC and Asbury Pump (25 cfs-capacity) on Baldwin Creek supply water to the Coleman Canal and Asbury pipe, respectively. The Asbury pipe meets the Coleman 2 siphon (part of the canal system) after a short run. The Coleman Canal, with a capacity of 380 cfs, delivers water 9.7 miles to the Coleman Forebay.

FERC License Article 33 requires a five cfs year-round minimum release from Coleman Diversion Dam to SFBC. However, the Battle Creek Agreement specifies a larger release of 30 cfs, plus or minus five cfs, for fisheries habitat purposes. Wildcat Diversion Dam, located on NFBC, formerly diverted water into the Wildcat pipe where it was conveyed 1.7 miles to the Coleman Canal. While FERC License Article 33 requires a three cfs minimum flow release from the Wildcat Diversion to NFBC, the Battle Creek Agreement has led to the temporary cessation of diversions at Wildcat Canal in 1996 and prompted a 33 cfs minimum, plus or minus five cfs, release for fishery habitat purposes.

From the forebay, two penstocks, with a combined capacity of 360 cfs, convey water to the 340-cfs-capacity Coleman Powerhouse (13 MW), which is limited to operating as an ROR facility. The powerhouse operates at a normal maximum gross head of 482 feet.

The water discharged from the Coleman Powerhouse enters a tailrace channel that flows into Battle Creek, which also supplies the Coleman National Fish Hatchery. FERC License Article 33 requires that the flows be maintained at a minimum of 150 cfs for the fish hatchery and for irrigation, either by releasing water from the powerhouse or by spilling from the forebay into the natural channel. The minimum release is measured by the USGS gage below the hatchery diversion structure.

As discussed above and in Chapter 5, Pacific Gas and Electric Company is currently participating in the Battle Creek Salmon and Steelhead Restoration Project, which consists of Federal and State resource agencies, Pacific Gas and Electric Company, and other stakeholders that are developing a long-term fish preservation and enhancement agreement in the Battle Creek system. Proposed terms for the agreement include (1) increasing the minimum instream flows from the present amount of three to five cfs year round to approximately 35-88 cfs adjusted seasonally; (2) decommissioning several diversion dams (Wildcat, Coleman, South Lower Ripley Creek and Soap Creek Diversion Dams) and transferring their associated water rights to instream uses; (3) screening and enlarging ladders at three diversion dams (Inskip, Eagle Canyon, and North Battle Creek feeder diversion dams); and (4) constructing new infrastructure (tailrace connectors) that eliminate mixing of North and South Fork waters and significantly reduce redundant screening requirements.

Water Quality. The beneficial uses associated with Battle Creek are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Battle Creek are:

- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Water emanating from the basin is used by the Coleman National Fish Hatchery which may indicate that quality is good. FERC License Article 19 requires Pacific Gas and Electric Company to take measures to prevent stream sedimentation and any other form of water pollution (FPC, 1975d). The current agreement will expire in 1999 and will have an option for two one-year renewals.

Groundwater. Groundwater within the system area can occur as bedrock seeps and springs. Groundwater can also occur locally in shallow alluvial deposits that line creek and river canyon bottoms and less commonly as hot springs that originate from deep faults and fractures in the batholithic rocks. Springs may occur in the vicinity of the facilities, originating from discontinuities between volcanic layers. There is an abundance of natural springs throughout the vicinity of the system, indicating abundant groundwater storage supply. Groundwater that may occur in the area is expected to be relatively soft and of high quality. Groundwater, if originating from sparsely occurring carbonate rocks, may be soda water or have high mineral content (Camp Dresser and McKee, 1997c). Pacific Gas and Electric Company uses the groundwater that naturally enters the surface flow of the basin but does not actively pump groundwater for power generation purposes.

4.3.4.2 DeSabla Regional Bundle

The DeSabla Region includes five FERC licenses covering 12 powerhouses and three unlicensed powerhouses with a combined capacity of 763.4 MW. There are four separate bundles located in the DeSabla Region: Hamilton Branch, Upper North Fork Feather River, Bucks Creek, and Butte Creek (see Figure 2-20 in Chapter 2). The following sections describe water resources for each of Pacific Gas and Electric Company's facilities in the DeSabla Region. Specifically, these sections describe each drainage basin and the location of the facilities, describe how water is used at each facility, describe the flow of water through the different facilities, and describe water diversion and use by other beneficial users. These sections also provide a description of water conveyance systems and capacities, as well as maximum powerhouse capacity.

When applicable, the unique water use constraints, such as physical capacity constraints, storage constraints, and regulatory restrictions (e.g., instream flow release requirements) included in FERC licenses, are discussed for each facility. Schematic diagrams depict the flow of water.

Regional Setting

The DeSabla Region contains slightly more than half of Pacific Gas and Electric Company's total reservoir capacity, at 1,332,000 acre-feet. Most of this storage is accounted for by Lake Almanor, which lies between the Cascade Mountains to the north and the Sierra Nevada to the south and east. Forty-six dams are fed by five streams in Butte and Plumas Counties. The area boasts the second-largest conventional hydropower capacity of 763 MW, generated in 15 powerhouses. The general layout of the DeSabla facilities and the major hydrographic features within this regional bundle are shown in Figure 2-19 in Chapter 2.

The majority of the DeSabla facilities (Hamilton Branch, Upper North Fork Feather River, Bucks Creek, Rock Creek-Cresta, and Poe bundles) lie in the watershed of the North Fork Feather River (NFFR), draining into Lake Oroville. The Feather River is the northernmost of four major rivers draining the western slope of the Sierra Nevada to the Sacramento Valley. Virtually all of the DeSabla Region's storage is accounted for by three NFFR facilities—Lake Almanor, Bucks Lake, and Butt Valley Reservoir. All other facilities operate essentially as run-of-river. Mean annual precipitation ranges from 39.5 inches at the Quincy Ranger Station to 67.5 inches at the Bucks Creek Powerhouse. The largest streamflows typically come from spring snowmelt in April and May or due to rain or rain-on-snow events secondary peaks in January and February.

The DeSabla-Centerville System and the Lime Saddle and Coal Canyon powerhouses lie in the Butte Creek and West Branch Feather River (WBFR) watersheds upstream of Lake Oroville and west of the NFFR facilities. Reservoirs in the DeSabla-Centerville system have minimal storage capacity, so the assets operate essentially as run-of-river facilities. Mean annual precipitation varies from about 27.4 inches at Oroville Dam, near the Coal Canyon area, to 64.2 inches at the DeSabla Powerhouse. Although the basin headwaters are high in the Sierra Nevada, most of the basin area is at lower elevation than the NFFR. Consequently, peak flows occur early in the year, typically January or February, and higher flows are sustained only into the beginning of June before dropping to low summer levels.

Pacific Gas and Electric Company currently conducts cloud seeding in the Lake Almanor, Butt Valley Reservoir, and Mountain Meadows Reservoir areas. Table 4.3-11 provides the location of the cloud seeding stations in the DeSabla Watershed Region.

Table 4.3-11 Cloud Seeding Stations for the DeSabla Region

Facility Name/Location	Property Owner	Location
Keddie Ridge	USFS – Plumas	SE1/4 of SW1/4, Sec 15, T27N R9E
Rattlesnake	USFS – Plumas	SE1/4 of NE1/4, Sec 11, T26N R8E
Keefer Ridge	USFS – Lassen	NE1/4 of SW1/4, Sec 30, T26N R7E
Butt Mountain	USFS – Lassen	SW1/4 of NE1/4, Sec 17, T27N,R6E

Facility Name/Location	Property Owner	Location
Stover Mountain	Sierra Pacific Industries	NE1/4 of NW1/4, Sec 31, T29N,R6E
Feather River Meadow	USFS – Lassen	NW1/4 of NE1/4, Sec 28, T28N, R5E
Christie Hill	USFS – Lassen	NW1/4 of NE1/4, Sec 9, T29N, R4E
Ohio Ridge	USFS – Lassen	NE1/4 of SW1/4, Sec 25, T27N R7E
Dyer Mountain	USFS – Lassen	NE1/4 of SW1/4, Sec 36, T28N R8E

Source: Will Walters, Aspen Environmental Group, 2000

Local Regulations and Policies

Refer to Section 4.3.2.

Bundle 5: Hamilton Branch

The Hamilton Branch Bundle consists of the Hamilton Branch Hydroelectric Generating Facility and associated appurtenances. This asset is a single generating facility, though it is hydrologically linked to the Upper North Fork Feather River Bundle.

Hamilton Branch (Non-FERC)

The Drainage Basin and Water Sources. The Hamilton Branch facilities, located in Plumas and Lassen Counties, are situated in the lower region of the Hamilton Branch tributary of the North Fork of the Feather River (NFFR). The Hamilton Branch Powerhouse (4.8 MW) tailrace water flows directly into Lake Almanor.

Hydroelectric Facilities. The asset consists of the Hamilton Branch Hydroelectric Generating Facility. The facility has a powerhouse, reservoir and diversion, and associated appurtenant facilities (for example, canals and penstocks), as shown in Figure 4.3-4.

Water Management. The powerhouse water storage facility is Mountain Meadows Reservoir, which impounds the waters of the Hamilton Branch at Indian Ole Dam, approximately 5.5 miles upstream of Lake Almanor. The reservoir has a gross capacity of 23,942 af. Water is stored in the reservoir during periods of high runoff and released into the Hamilton Branch NFFR during periods of low flow. Maximum gross head at the powerhouse is 410 feet (Powerhouse Physical Data Sheets, 1998).

Water released from the dam transits 1.8 miles of the river before reaching the Hamilton Branch Diversion Dam. From the Hamilton Branch Diversion Dam water is diverted in the Hamilton Branch Canal, a 3.3-mile-long flume and ditch facility with a capacity of 210 cfs. Additional water is fed into the canal from small diversions on Clear Creek, Spring Creek, and the Hamilton Branch at Red Bridge. At Clear Creek and Red Bridge, diverted water is added to the canal by way of a pump lift. Minimum flows are released into each of these diverted streams. Water discharged from the powerhouse flows directly into Lake Almanor.

Water management in the reservoir is governed primarily by power production and fish and wildlife habitat considerations. An agreement between Pacific Gas and Electric Company and CDFG regulates water management within Mountain Meadows Reservoir, stipulating drawdown limits and pool elevations in different seasons and water year types. It also establishes minimum flow releases from the reservoir and at four other points of diversion (PG&E Co., 1989a).

Table 4.3-12 Minimum Releases Associated with the Hamilton Branch System

Facility	Time Period	Minimum Release (cfs)
Indian Ole Dam	Year Round	2
Hamilton Branch Diversion Dam	Year Round	4
Red Bridge Diversion	Year Round	4
Clear Creek Diversion	Year Round	3
Spring Creek Diversion	Year Round	1

Source: PG&E Co., 1999

Pacific Gas and Electric Company must release a minimum flow of two cfs, when combined with dam leakage, from Indian Ole Dam into Hamilton Branch throughout the year. A minimum flow of four cfs is released from the Hamilton Branch Diversion Dam into Hamilton Branch, as measured at the entrance to the fish ladder, throughout the year. In addition, Pacific Gas and Electric Company must release a minimum flow of four cfs at Red Bridge Diversion, three cfs at Clear Creek Diversion, and one cfs at Spring Creek Diversion. These stipulations of the agreement effectively establish water use patterns in the powerhouse area.

Hamilton Branch Powerhouse is operated as a baseload facility due to the length of its canal system and its relatively low generator capacity.

Water Quality. The beneficial uses associated with the NFFR are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of NFFR are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Information related to water quality can be inferred from fish populations living in the Hamilton Branch water bodies. Stocking by CDFG of catfish and black bass in Mountain Meadows Reservoir suggests a warm body of water that may be low in DO. Conversely, stocking of salmonids (brook, brown, and rainbow trout) in the Hamilton Branch by CDFG suggest a cold, well-aerated environment in the river.

Groundwater. No information was collected about groundwater in the Hamilton Branch Bundle because the powerhouse does not use it.

Bundle 6: Upper North Fork Feather River

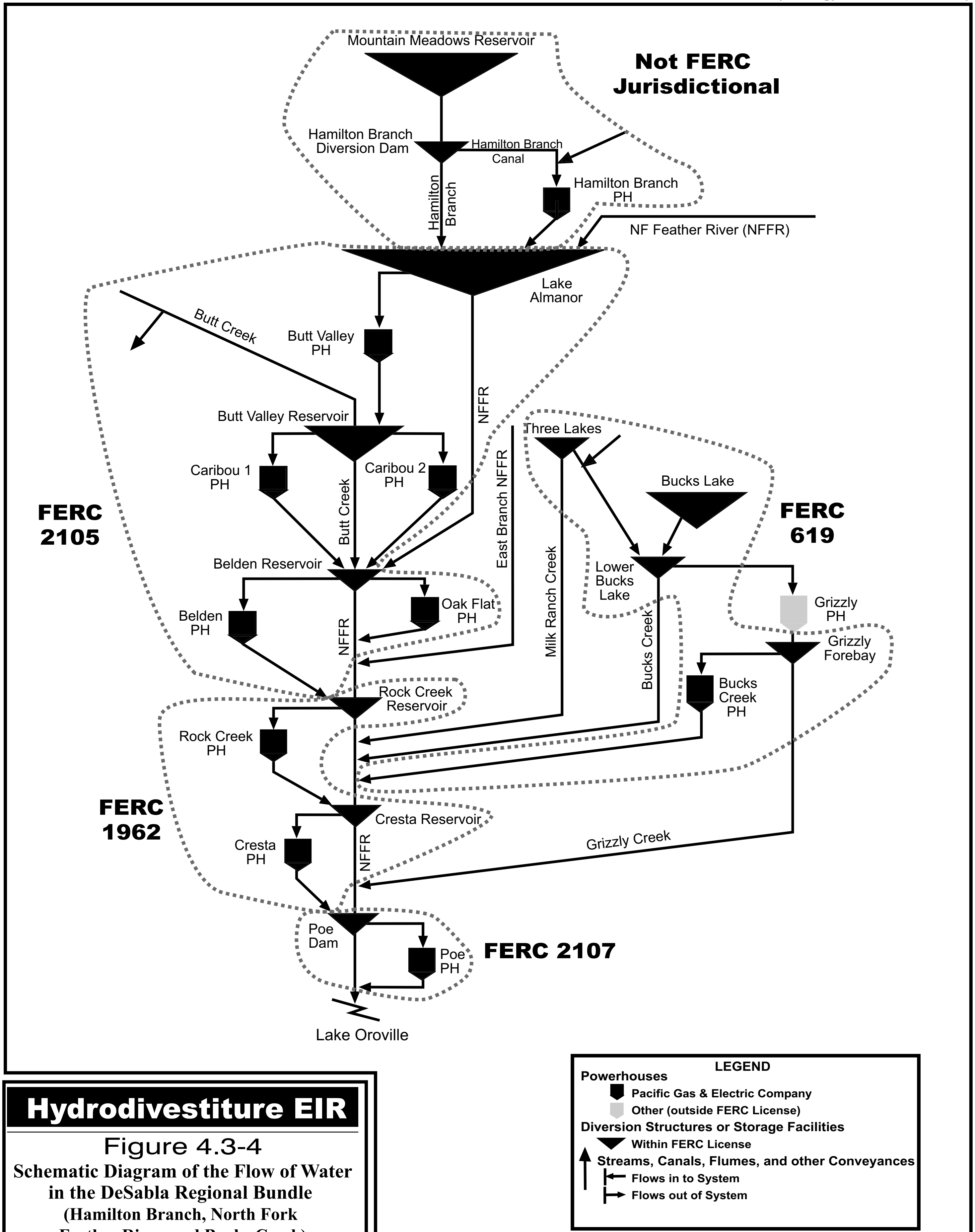
The Upper North Fork Feather River Bundle consists of FERC No. 2105 (the Butt Valley, Caribou 1 and 2, Oak Flat, and Belden Hydroelectric Generating Facilities and associated appurtenances), FERC No. 1962 (the Rock Creek and Cresta Hydroelectric Generating Facilities and associated appurtenances), and FERC No. 2107 (the Poe Hydroelectric Generating Facility and associated appurtenances). These assets are being bundled together to maintain FERC licenses No. 2105, 1962, and 2107, which share overlapping boundaries. In addition, these facilities are hydrologically linked, which will be maintained under this bundling. The facilities are also hydrologically linked to the Hamilton Branch Bundle and the Bucks Creek Bundle.

Upper North Fork Feather River (FERC 2105)

The Drainage Basin and Water Sources. The Upper North Fork Feather River System is located in Plumas County, on the NFFR, a tributary of the Feather River. The NFFR lies entirely within the NFFR basin, which drains the northern end of the Sierra Nevada and the southern end of the Cascade Range into the Sacramento River. The headwaters of the NFFR lie on the southeastern slopes of Mt. Lassen, in Plumas County. The main river channel flows for approximately 63 miles before reaching Lake Oroville, in Butte County. Included within its flow is the East Branch North Fork Feather River, which extends 18 miles eastward, and includes more than 30 smaller tributaries that converge into the NFFR, contributing to the 2,200-square-mile basin area. The drainage area within the NFFR basin utilized by the system is 612 square miles, as measured from directly below Belden Dam (USGS, 1997), the most downstream diversion facility.

Hydroelectric Facilities. The asset consists of the Butt Valley, Caribou 1 and 2, Oak Flat, and Belden hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-4.

Water Management. The primary storage facility is Lake Almanor, a 1,142,964 acre-foot (af) reservoir on the NFFR (PG&E Co., 1987). Lake Almanor provides the major regulation of water flow through the NFFR. Water management within the lake is coordinated to optimize the operation of a chain of seven powerhouses throughout the river and to provide for local recreation. Water is generally stored for the first half of the year (January-May) and released during the second half.



Hydrodivestiture EIR

Figure 4.3-4

Schematic Diagram of the Flow of Water in the DeSabla Regional Bundle (Hamilton Branch, North Fork Feather River, and Bucks Creek)

Aspen Environmental Group

Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

The end of the year target water storage level is generally around 650,000 af, but is highly variable.

As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.

Table 4.3-13 Minimum Releases Associated with the Upper North Fork Feather River System

Facility	Time Period	Minimum Release (cfs)
Lake Almanor	Year Round	35[a], plus flushing flows
Belden Dam	End of April[b] – Labor Day	140
	Rest of year	60

a License requires release of 25,000 af per year subject to a release schedule from CDFG. Releases have historically been maintained at 35 cfs. bBeginning the Friday preceding the last Saturday of April, to correspond with opening of trout season.

Source: PG&E Co., 1999

The end-of-year target water storage level was established in 1986 by Pacific Gas and Electric Company in response to an inquiry by FERC. It is generally established as 650,000 af, but is dependent on the amount of runoff carry-over from the previous year (PG&E Co., 1996c). Storage must be maintained above 500,000 af year-round, while maximum storage shall not exceed 1,142,960 af based on a maximum reservoir elevation set by the California Division of Dam Safety (PG&E Co., 1986b).

An agreement between Pacific Gas and Electric Company and DWR and Western Canal Water District requires that 145,000 af be delivered to Lake Oroville from Lake Almanor storage between March 1 and October 31 (PG&E Co., 1986c). FERC License Article 26 requires a total annual release of 25,000 af each calendar year from Lake Almanor Dam to the NFFR, subject to a release schedule provided by the CDFG. In addition, CDFG may request flushing flow releases from the dam to improve fish spawning habitat in an annual amount not to exceed 1,000 af single-time-release subject to a cumulative total not to exceed 5,000 af. While the distribution of these amounts is subject to consultation with CDFG, dam releases are normally maintained at 35 cubic feet per second (cfs) (FERC, 1964).

Additional outflows from Lake Almanor include the diversion of water into the Prattville Tunnel, which leads to the Butt Valley Powerhouse (41.0 MW) on Butt Creek, and spill releases of up to 2000 cfs into the NFFR from the dam outlet tower. Under normal operating conditions, diversions into the Prattville Tunnel generally range from 800 to 2,180 cfs. The normal maximum capacity of the Butt Valley Powerhouse is 1,620 cfs, though it is capable of handling the maximum tunnel flows. It operates at a normal maximum gross head of 362 feet (Powerhouse Physical Data Sheets, 1998).

Tailrace water from the Butt Valley Powerhouse immediately enters Butt Valley Reservoir, which lies about three miles south of Lake Almanor on Butt Creek and has a usable storage capacity of 49,897 af (DeSabla Hydro 12). Due to the large storage capacity in Lake Almanor, Butt Valley Powerhouse can be operated as a peaking facility to respond to system energy demands. Pacific Gas and Electric Company releases water from the Butt Valley Reservoir directly into two 1.8-mile tunnels feeding the penstocks for Caribou 1 and 2 Powerhouses (195 MW). The maximum flow capacity of the Caribou 1 and 2 Powerhouses is 1,114 and 1,464 cfs, respectively. The powerhouses have a normal maximum gross head of 1,150 and 1,151 feet respectively (Powerhouse 1998). The Caribou units, which lie along the NFFR, are also operated in peaking mode, using available storage at Butt Valley Reservoir to respond quickly to changes in energy demands. Water discharging from these powerhouses flows directly into Belden Reservoir (2,400 af), located on the NFFR approximately ten miles downstream from Lake Almanor Dam.

Belden Reservoir serves as the forebay to both Oak Flat Powerhouse (1.3 MW) and Belden Powerhouse (125 MW). The 140 cfs-capacity Oak Flat Powerhouse, located at the base of Belden Dam on the NFFR, is run as a baseload facility with its output determined by the minimum instream flow requirement. The Oak Flat Powerhouse operates at a normal maximum gross head of 137 feet (Powerhouse 1998). Water released through Oak Flat Powerhouse immediately enters the NFFR.

Pacific Gas and Electric Company also diverts water from Belden Reservoir into a 6.6-mile-long tunnel to the 2,410 cfs-capacity Belden Powerhouse, which is located on Yellow Creek, immediately upstream of its confluence with the NFFR. The powerhouse operates at a normal maximum gross head of 770 feet (Powerhouse 1998). Belden Powerhouse can be operated as a peaking facility only when operated in coordination with the upstream Caribou powerhouses and the downstream Rock Creek, Cresta, and Poe powerhouses.

The flow released to the NFFR below Belden Dam must total 64,000 af each calendar year. The flow schedule provided by the CDFG requires a release of 140 cfs beginning the Friday preceding the last Saturday in April, in order to correspond to the opening of trout season. After Labor Day, flows are reduced to 60 cfs (FERC, 1991A). The mean annual flow discharged from Belden Dam between 1970 and 1996 was 135 cfs.

Water Delivery and Domestic Use. As described in Chapter 2, Pacific Gas and Electric Company has water rights in the Upper North Fork Feather River System. There are additional contracts for water delivery or supply, including an annual requirement for delivery of 145,000 acre-feet from Lake Almanor to Lake Oroville between March and November.

Water Quality. The beneficial uses associated with the NFFR are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality

Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the NFFR are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Lake Almanor has the same listed uses as the NFFR, with the exception of municipal supply (MUN) and non-contact recreation (REC-2). Lake Almanor also supports warm freshwater habitat (WARM).

Water quality in the area is excellent. Residential development at Lake Almanor, however, has the potential to impact water quality. In recognition of this potential, the Chester Wastewater Treatment Facility has planned improvements to avoid releases to Lake Almanor (FERC 1994a). The high quality of the system waters was demonstrated by studies conducted by Pacific Gas and Electric Company in 1984 (PG&E Co., 1987). These studies showed the NFFR to be a soft, moderately alkaline stream containing low to moderate levels of dissolved solids and total suspended solids. Solids concentrations vary depending on runoff conditions. Nutrient levels are sufficient to support moderate productivity. Dissolved oxygen (DO) and pH levels are within the range of values considered necessary for the maintenance of healthy fish populations.

FERC License Article 27 requires that Pacific Gas and Electric Company not release debris and silt laden water into the NFFR or any of its tributaries from gravel-washing activities connected with fish habitat enhancement activities at the facilities. In addition, FERC License Article 29 requires that Pacific Gas and Electric Company avoid sudden releases of water into natural channels that may cause bank erosion, raised turbidity, and sedimentation (FERC 1995).

Water temperature in the NFFR is influenced by the temperature of water released from Lake Almanor and other storage facilities. In general, water temperatures are cold in the NFFR above Caribou 1 and 2 Powerhouses, stemming in part from Pacific Gas and Electric Company's decision in 1982 to release water from the lower gate on Lake Almanor Dam outlet tower. The release water, approximately 35 cfs, is warmed by about 5°C to 11.4-16° by the time it reaches Belden Reservoir, which is approximately ten miles downstream. (PG&E Co., 1996c). Pacific Gas and Electric Company contends that water quality investigations conducted by the Company have indicated that the water quality of the NFFR is suitable for all beneficial uses identified by the CVRWQCB (PG&E Co., 1987). The Company's findings were supported by an independent assessment by FERC, which declared the water quality in the area as excellent (FERC, 1994a). Staff from the SWRCB disagree with this assertion, citing negative impacts to Cold Freshwater

Habitat, resulting from low minimum flows below Pacific Gas and Electric Company facilities between Rock Creek and Lake Oroville (SWRCB, 2000).

Summer temperature profiles of Lake Almanor show that it is a stratified lake with a warm upper layer (epilimnion) that extends to about 30 feet and a colder (hypolimnion) below 40 feet. The near surface layer is generally warmer than 20°C in the summer and the bottom is 10-12°C (PG&E Co., 1996c). A similar pattern of stratification exists with respect to DO, with high levels occurring in the upper portion of the lake, and low levels near the lake bottom. Water of low DO released from the Lake Almanor Dam outlet tower is rapidly aerated through the outlet structure to near saturation levels. Water released through Butt Valley Powerhouse (Prattville Tunnel) is taken from the more shallow Prattville Intake. Pacific Gas and Electric Company has studied the feasibility of options to release colder water in an effort to enhance downstream water temperatures at the Rock Creek-Cresta Facilities (FERC No. 1962).

Turbidity in Lake Almanor is usually less than 5 nephelometer turbidity units (NTU). Significant fluctuations in turbidity and suspended solids have been recorded, primarily in response to upstream weathering and erosion, grazing, logging, and mining activities in the East Branch NFFR. Turbidity is generally low, ranging from 0 to 2 NTU throughout much of the year. pH values ranged from 6.7 to 8.5 in Lake Almanor and were similar to those measured in the NFFR. Turbidity, pH, and conductivity all meet the objectives for the basin, as analyzed by Pacific Gas and Electric Company in 1996 (PG&E Co., 1996c).

Pacific Gas and Electric Company is involved in the Coordinated Resource Management Plan (CRMP) work being done in the Feather River Basin. Pacific Gas and Electric Company has been a voluntary contributor to erosion control and stream restoration projects since 1984. Pacific Gas and Electric Company's participation in this program is not required under any of its FERC licenses or regulatory conditions.

Groundwater. No information was collected about groundwater in the Upper North Fork Feather River Bundle because the facilities do not use it.

Rock Creek-Cresta (FERC 1962)

The Drainage Basin and Water Sources. The Rock Creek-Cresta System, located in Butte and Plumas Counties, is situated on the lower reaches of the NFFR. The NFFR basin is a branch of the Feather River that drains the northern end of the Sierra Nevada and the southern Cascade Range into the Sacramento River. The headwaters of the NFFR lie on the southeastern slopes of Mt. Lassen, in Plumas County. The main river channel flows for approximately 63 miles before reaching Lake Oroville, in Butte County. Included within its flow is the East Branch NFFR, which extends 18 miles eastward and includes more than 30 smaller tributaries that converge into the NFFR, contributing to the 2,200-square-mile basin area. The drainage area within the NFFR watershed that is utilized by the system is 1,914 square miles, as determined from below Cresta Dam (USGS, 1997).

Hydroelectric Facilities. The Rock Creek-Cresta System consists of the Rock Creek and Cresta hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-4.

Water Management. The system is hydrologically linked to Pacific Gas and Electric Company's Upper North Fork Feather River System, Bucks Creek System, and Poe System, and operations are coordinated to maximize generation. Water stored upstream in Pacific Gas and Electric Company's Lake Almanor is released during the summer and fall months to power the Rock Creek-Cresta System, while runoff emanating from the East Branch NFFR supplies significant flow during winter and spring.

The upstream facility begins with Rock Creek Reservoir, which captures water from two primary sources: (1) water discharged from the Belden Powerhouse, the lowermost facility of Pacific Gas and Electric Company's Upper North Fork Feather River System, and (2) inflow from the NFFR, which consists of releases made at the Belden Reservoir plus inflow from the East Branch NFFR, a major NFFR tributary. The long-term average inflow to the reservoir is estimated to be approximately 2,400 cfs (PG&E Co., 1981a). Rock Creek Reservoir has a drainage area of 1,771 square miles and gross storage capacity of 4,400 af, although the accumulation of sediments in the reservoir has reduced its capacity (PG&E Co., 1989b). Water is diverted from the Rock Creek Reservoir into a tunnel with a 2,880-cfs capacity. The water from the tunnel enters two penstocks that lead to the Rock Creek Powerhouse (112 MW). The powerhouse operates at a normal maximum gross head of 535 feet (Powerhouse Physical Data Sheets 1998). Pacific Gas and Electric Company also releases water from Rock Creek Dam to the NFFR, where it flows 8.4 miles from the Rock Creek Reservoir to Cresta Reservoir.

Minimum flows within this bundle, required under the FERC license, are summarized in Table 4.3-14 below and further described in the following text.

Table 4.3-14 Minimum Releases Associated with the Rock Creek-Cresta System

Facility	Time Period	Minimum Release (cfs)
Rock Creek Dam	May – October November - April	100 (normal years)* 50 (normal years)*
Cresta Dam	Year Round	50

*FERC License Article 13 allows for a dry year reduction.

Source: PG&E Co., 1999

Seasonally and water year-adjusted minimum flows at the two dams are stipulated in FERC License Article 13 (FERC, 1947). When a new license is issued, these releases are expected to increase to levels stipulated in a 1991 Fish and Wildlife Agreement between Pacific Gas and Electric Company and CDFG, which will be incorporated into the new license (PG&E Co., 1991). FERC License Article 13 requires a minimum flow release from Rock Creek Dam to the NFFR of 100 cfs from May 1 through October 31, and 50 cfs from November 1 through April 30, although seasonal spills during runoff periods have resulted in a mean annual flow in the river of 460 cfs between 1987 and 1996 (USGS, 1997). Under a 1988 letter agreement, Pacific Gas and Electric Company agreed to forego a dry year reduction that is allowed under FERC License Article 13 (PG&E Co., 1988).

Tailrace water from Rock Creek Powerhouse discharges into the NFFR and immediately enters Cresta Reservoir. In addition to the tailrace water, Cresta Reservoir captures water from Bucks Creek and the Bucks Creek Powerhouse via the NFFR. Other sources of inflow to the reservoir include the NFFR downstream of Rock Creek Dam, and tributary inflow from several small creeks. The Cresta Reservoir has a drainage area of 1,880 square miles and a gross storage capacity of 4,140 af, although, as with Rock Creek Reservoir, storage in the Cresta Reservoir has been diminished due to sedimentation.

Water is diverted from the Cresta Reservoir into a tunnel and penstock combination leading to the Cresta Powerhouse (70.0 MW), 4.1 miles downstream of the reservoir. The maximum capacity of Cresta Powerhouse is 3,510 cfs, and it operates at a normal maximum gross head of 290 feet (Powerhouse Physical Data Sheets 1998).

FERC License Article 13 requires a minimum flow of 50 cfs, measured at gauge NF-56, below Cresta Reservoir. These releases are augmented by spills occurring during winter and spring high flow events (PG&E Co., 1998b).

Rock Creek and Cresta Powerhouses can be operated as peaking facilities, but the operation must be coordinated with the upstream Belden Powerhouse and downstream Poe Powerhouse (120.0 MW). During periods of high runoff they may be operated as baseload facilities in order to pass inflows from the unregulated East Branch NFFR through to Lake Oroville.

Water Quality. The beneficial uses associated with the NFFR are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the NFFR are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Waters of the NFFR, including the system reservoirs, can be classified as soft, moderately alkaline waters containing low concentrations of trace inorganic constituents and low-to-moderate concentrations of suspended and total dissolved solids. Dissolved oxygen, pH, and conductivity levels in the NFFR, reservoirs, and tributaries are well within a range considered necessary for maintaining healthy fish populations (PG&E Co., 1989c).

Water and land use practices upstream of the system have a significant effect on water quality in the reservoirs and NFFR reaches. The Rock Creek and Cresta Reservoirs are both shallow and narrow bodies of water. High inflows, short retention time, and well-mixed conditions of these reservoirs limit thermal and/or DO stratification. Summer water temperatures measured in the reservoirs between 1981-1985 ranged from 18 to 22°C (CDFG, 1988). Staff from the SWRCB noted that operations of the Rock Creek and Cresta facilities have also negatively affected Cold Freshwater Habitat due to temperature impacts (SWRCB, 2000).

A more prevalent water quality characteristic of the FERC-licensed waters is the significant fluctuations in turbidity and suspended solids. Studies conducted by Pacific Gas and Electric Company between 1987 and 1989 show levels of these parameters to be generally low throughout much of the year, ranging from 0 to 2 NTU and from 0 to 10 mg/l, respectively. These levels increased substantially during high runoff periods, reaching values of up to 100 NTU and 170 mg/l respectively (Planning Associates, 1993). Such increases occur primarily in response to upstream weathering and erosion, due primarily to grazing, logging, and mining activities in the East Branch NFFR (Pacific Gas & Electric Company, 1989c). Of the total 1,771 square miles draining into Rock Creek Reservoir, approximately 1,026 square miles are part of the East Branch NFFR watershed (PG&E Co., 1989c).

Pacific Gas and Electric Company and CDFG entered into an agreement in 1991 that was intended to protect water quality. Under the terms of the agreement, Pacific Gas and Electric Company would install, operate, and maintain a flexible curtain wall at the Prattville Intake of Lake Almanor to maintain water temperature in the Rock Creek-Cresta bypass reaches of the NFFR (PG&E Co., 1991). SWRCB staff note that this curtain wall was never installed (SWRCB, 2000). The 1991 agreement also stipulated that Pacific Gas and Electric Company make supplemental water releases at Rock Creek Dam during summer months of up to 3,600 af (as requested by the CDFG) for the purposes of providing water temperatures in the NFFR for protection of fishery resources. The 1991 agreement was superceded by the Rock-Creek Cresta Agreement, which includes detailed specifications of minimum instream flows, pulse flows, and ramping rates that must be met below Rock Creek and Cresta Reservoirs (Rock Creek-Cresta, 2000). One of the "Disputed Subjects Not Resolved" by the Rock Creek-Cresta Agreement was listed as follows:

> Reasonable water temperature control measures for protection of water resources that may be sought or required in the relicensing proceedings for the North Fork Feather River Project (No. 2105) and Poe Project (2107); or in any proceeding to amend the New Project License to provide for coordinated operations of this Project, the North Fork Feather River Project, and the Poe Project.

Pacific Gas and Electric Company is involved in the CRMP work being done in the Feather River Basin. Pacific Gas and Electric Company has been a voluntary contributor to erosion control and stream restoration projects since 1984. Pacific Gas and Electric Company's participation in this program is not required under any of its FERC licenses or regulatory conditions.

Groundwater. No information was collected about groundwater in the Rock Creek-Cresta Bundle. The Pacific Gas and Electric Company facilities in this bundle do not use groundwater.

Poe (FERC 2107)

The Drainage Basin and Water Sources. The Poe Facility, located in Butte County, is situated in the lower reaches of the NFFR, directly upstream of Lake Oroville (owned by DWR). The NFFR basin is a branch of the Feather River that drains the northern end of the Sierra Nevada and the southern Cascade Range into the Sacramento River. The headwaters of the NFFR lie on the southeastern slopes of Mt. Lassen, in Plumas County. The main river channel flows for approximately 63 miles before reaching Lake Oroville, in Butte County. Included within its flow is the East Branch NFFR, which extends 18 miles eastward and includes more than 30 smaller tributaries that converge into the NFFR, contributing to the 2,200 square mile basin area. The drainage area within the NFFR watershed that is utilized by the Poe System is 1,953 square miles as determined below Poe Dam, the most downstream diversion facility (USGS, 1997).

Hydroelectric Facilities. The asset consists of the Poe Hydroelectric Generating Facility. The facility consists of a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-4.

Water Management. The system is hydrologically linked to Pacific Gas and Electric Company's Upper North Fork Feather System, Bucks Creek System and Rock Creek-Cresta System, and operations are coordinated to maximize generation. Water stored upstream in Pacific Gas and Electric Company's Lake Almanor may be released during the summer and fall months to power the Poe Facility, while runoff emanating from the East Branch NFFR may supply sufficient water during winter and spring.

The Poe Reservoir captures water in the NFFR from releases made at the Cresta Powerhouse and from the Cresta Dam. Water is diverted from Poe Reservoir into a 6.2-mile-long tunnel, with a normal maximum flow of 3,700 cfs, to the 120-MW Poe Powerhouse. The powerhouse operates at a normal maximum gross head of 488 feet (Powerhouse Data Sheet 1998). Water from the powerhouse tailrace is impounded by Lake Oroville.

FERC mandated minimum flows within this bundle are summarized in Table 4.3-15 below and further described in the following text.

Table 4.3-15 Minimum Releases Associated with the Poe System

Facility	Time Period	Minimum Release (cfs)
Poe Diversion Dam	Year Round	25
Downstream gage at Big Bar	Year Round	50

Source: PG&E Co., 1999

Pacific Gas and Electric Company also releases water directly into the NFFR from Poe Dam, in accordance with the FERC license. FERC License Article 26 stipulates that a minimum flow of 50 cfs must be maintained at all times in the NFFR at the downstream gaging station at Big Bar and that a minimum flow of 25 cfs is required for the Poe Diversion Dam (FPC, 1965b). FERC License Article 27 further requires that system operations avoid sudden release of large flows into the NFFR when the control of such releases is reasonably possible. Nevertheless, high spring flows in the NFFR often result in unavoidable spill. Mean annual flow at the Pulga gaging station in the NFFR for water year 1996, for example, was 1,861 cfs (USGS, 1997).

Water Quality. The beneficial uses associated with the NFFR are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the NFFR are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Waters of the NFFR, including the Poe Reservoir, can be classified as soft, moderately alkaline waters containing low concentrations of trace inorganic constituents and low-to-moderate concentrations of suspended and total dissolved solids. Levels of dissolved oxygen, pH and conductivity in the NFFR, Poe Reservoir and tributaries are well within a range considered necessary for maintaining healthy fish populations (Pacific Gas & Electric Company, 1989c). Water temperature for trout habitat is marginal and staff from the SWRCB noted that operations of Company facilities on the NFFR have negatively impacted temperatures, and therefore Cold Freshwater Habitat, below Poe (SWRCB, 2000).

Water and land use practices upstream of the system have a significant effect on water quality in the reservoir and NFFR reaches. Poe Reservoir is a shallow and narrow body of water. High inflows, short retention time, and well-mixed conditions of this reservoir limits thermal and/or DO stratification. A more prevalent water quality characteristic of the FERC-licensed waters is the significant fluctuations in turbidity and suspended solids. Studies conducted by Pacific Gas and Electric Company between 1987 and 1989 show levels of these parameters to be generally low throughout much of the year, ranging from 0 to 2 NTU and from 0 to 10 mg/l, respectively. These levels increased substantially during high runoff periods, reaching values of up to 100 NTU and 170 mg/l, respectively (Planning Associates, 1993). Such increases occur primarily in response to upstream weathering and erosion, due primarily to grazing, logging, and mining activities in the East Branch NFFR (PG&E Co., 1989c). Of the total 1,953 square miles draining into Poe Reservoir, approximately 1,026 square miles are part of the East Branch NFFR watershed (PG&E Co., 1989c).

Sedimentation problems experienced at the upstream Rock Creek-Cresta System are not an issue at the Poe Facility due to the different spill gate configuration at Poe Dam.

Pacific Gas and Electric Company is involved in the CRMP work being done in the Feather River Basin. Pacific Gas and Electric Company has been a voluntary contributor to erosion control and stream restoration projects since 1984. Pacific Gas and Electric Company's participation in this program is not required under any of its FERC licenses or regulatory conditions.

Groundwater. No information was collected about groundwater in the Poe Bundle. The Poe Hydroelectric Generating Facility does not use groundwater.

Bundle 7: Bucks Creek

The Bucks Creek Bundle consists of FERC No. 0619 (the Bucks Creek Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility, though it is hydrologically linked to the Upper North Fork Feather River Bundle.

Bucks Creek (FERC 0619)

The Drainage Basin and Water Sources. The Bucks Creek System, located in Plumas County, is situated on three tributaries of the NFFR (Bucks, Grizzly, and Milk Ranch Creeks) that flow in a westerly direction from the crest of the Sierra Nevada to the NFFR. The NFFR is a branch of the Feather River that drains the northern end of the Sierra Nevada and the southern Cascade Range into the Sacramento River.

Hydroelectric Facilities. The Bucks Creek System consists of the Bucks Creek Hydroelectric Generating Facility. The facility has a powerhouse, reservoirs, and associated appurtenant facilities (for example, conduits and penstocks) distributed within the NFFR watershed. The Bucks Creek System also includes the Grizzly Powerhouse (20 MW) (owned by the City of Santa Clara, California, and operated by Pacific Gas and Electric Company under a coordinated dispatch agreement between Pacific Gas and Electric Company and the City of Santa Clara) (FERC, 1990). Pacific Gas and Electric Company's agreement with the City of Santa Clara specifies that water management for both the Bucks Creek and Grizzly powerhouses be done by Pacific Gas and Electric Company. Figure 4.3-4 shows a schematic of the Bucks Creek System.

Water Management. Bucks Lake is the largest of the four storage facilities in the system. It is a 105,327 af reservoir that captures natural runoff of Bucks Creek and its tributaries within a 28.6-square-mile area (USGS, 1997). The streams feeding the lake drain the western crest of the Sierra Nevada in Plumas County, reaching an elevation of approximately 7,200 feet. Water is released from Bucks Lake Dam directly into a second reservoir, the 5,800 af Lower Bucks Lake.

The second major source of water to Lower Bucks Lake is Three Lakes, a reservoir on Milk Ranch Creek. Three Lakes is the highest storage facility in the system and also the smallest, with a usable storage capacity of 606 af (Camp Dresser and McKee 1997c). Water released from Three Lakes flows down Milk Ranch Creek approximately 1,500 feet where it is diverted into the Milk Ranch Conduit. The conduit then conveys the water approximately eight miles to Lower Bucks Lake (Camp Dresser and McKee, 1997c). Additional water is added to the conduit from several diversions along its length (USGS, 1997).

FERC mandated minimum flows are summarized in Table 4.3-16 and further described in the following paragraphs.

Table 4.3-16 Minimum Releases Associated with the Bucks Creek System

Facility	Time Period	Minimum Release (cfs)
Lower Bucks Lake Dam	April – November	3
	December - March	1
Grizzly Forebay	April – November	4
	December - March	2

Source: PG&E Co., 1999

Minimum reservoir elevations and minimum streamflow releases for the system were established by an agreement with CDFG (PG&E Co., 1968), and incorporated into the FERC license (FPC, 1974a). In addition, a Memorandum of Understanding between Pacific Gas and Electric Company, the USFS, and the City of Santa Clara sets requirements for streamflow releases and reservoir operation at the facilities (PG&E Co., 1998d). FERC License Article 13 specifies reservoir operation criteria for Bucks Lake and minimum elevation levels for all storage facilities, including Bucks Lake, Lower Bucks Lake, Grizzly Forebay, Lower Three Lakes, and Middle Three Lakes.

There are no minimum release requirements for Milk Ranch Creek below Milk Ranch Conduit. However, seepage below the diversion is joined by several small tributaries shortly downstream.

Water is released from Lower Bucks Lake at two locations: (1) into Bucks Creek, and (2) into the Grizzly Tunnel and penstock leading to the Grizzly Powerhouse.

Releases into Bucks Creek are made by Pacific Gas and Electric Company at the Lower Bucks Lake Dam, below Lower Bucks Lake and Grizzly Forebay, in accordance with FERC License Article 13. Between April 1 and November 30, the release to Bucks Creek is three cfs; from

December 1 through March 31 the release is 1 cfs. A set of interim minimum flows at these same locations have also been established in FERC License Article 104 to commence on November 1, 2004 (FERC, 1988).

Water that is diverted from Lower Bucks Lake to the Grizzly Powerhouse flows into the 1,100 af Grizzly Forebay (the forebay elevation is typically maintained at the tailrace of the Grizzly Powerhouse). The water in Grizzly Forebay, composed of inflow from Grizzly Powerhouse and Grizzly Creek, is diverted into another tunnel and penstock leading to Pacific Gas and Electric Company's Bucks Creek Powerhouse (65 MW), which is located on the NFFR. The maximum flow capacity of the Bucks Creek Powerhouse is 384 cfs, and it operates at a normal maximum gross head of 2,558 feet (Powerhouse Physical Data Sheets 1998). Bucks Creek and Grizzly Powerhouses are operated by Pacific Gas and Electric Company as baseload facilities.

In accordance with FERC License Article 13, Pacific Gas and Electric Company also releases instream flows from the Grizzly Forebay into Grizzly Creek, which then flows 6.2 miles before joining the water of the NFFR. Minimum flow releases are 4 cfs from April 1 through November 30, and two cfs from December 1 through March 31.

Water Delivery and Domestic Use. As described in Chapter 2, Pacific Gas and Electric Company has water rights in the Bucks Creek System. There are additional contracts for water delivery or supply.

Water Quality. The beneficial uses associated with the NFFR and its tributaries are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the NFFR are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Water quality in the area is excellent, largely due to the fact that system waters flow through high elevation, moderately steep, rugged, unpopulated terrain (PG&E Co., 1981). The Pacific Gas and Electric Company contends that FERC-licensed waters are suitable for all beneficial uses identified by the CVRWQCB. Water quality studies conducted in 1973 by Pacific Gas and Electric Company showed that water temperature, DO, and pH all fell within acceptable ranges (PG&E Co., 1981). Subsequent water quality investigations conducted in 1981 by Pacific Gas and Electric Company throughout the system area, including the storage facilities and the streams, provided similar results, showing water quality to be excellent throughout the Bucks Creek basin.

FERC License Article 20 requires Pacific Gas and Electric Company to take measures to prevent stream siltation and other forms of water pollution (FPC 1974b).

Groundwater. No information was collected about groundwater in the Buck's Creek Bundle as the Bucks Creek Hydroelectric Generating Facility does not use groundwater.

Bundle 8: Butte Creek

The Butte Creek Bundle consists of FERC No. 0803 (the Toadtown, Centerville, and DeSabla Hydroelectric Generating Facilities and associated appurtenances), and two unlicensed facilities (the Lime Saddle and Coal Canyon Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 0803.

DeSabla-Centerville (FERC No. 0803)

The Drainage Basin and Water Sources. The DeSabla-Centerville System, located in Butte County, is situated within two separate north-to-south drainage basins of the Sierra Nevada: the West Branch Feather River (WBFR) and Butte Creek. Both drainage basins have headwaters at an elevation of approximately 7,000 feet on the Sierra Nevada crest. The WBFR drains into Lake Oroville on the Feather River. The drainage area within the WBFR watershed utilized by the system is 46 square miles, as determined at Hendricks Diversion, the downstream diversion facility (USGS, 1997). Butte Creek flows directly into the Sacramento River. The drainage area within Butte Creek utilized by the system is approximately 60 square miles (PG&E Co., 1982a).

Hydroelectric Facilities. The asset consists of the Toadtown, DeSabla, and Centerville hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-5.

Water Management. The system diverts waters from the WBFR and Butte Creek to three powerhouses (Toadtown, DeSabla and Centerville) located in the Butte Creek watershed. The WBFR facility consists of two high elevation storage reservoirs and a diversion/canal system that transports water into the Butte Creek watershed.

As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below some facilities. These are summarized below and further described in the following text.

Table 4.3-17 Minimum Release Associated with the DeSabla-Centerville System

Facility	Time Period	Minimum Release (cfs)
Round Valley Reservoir	Year Round	0.5 (normal years) 0.1 (dry years)
Philbrook Reservoir	Year Round	2
Hendricks Diversion	Year Round	15 (normal years)

Facility	Time Period	Minimum Release (cfs)
		7 (dry years)
Butte Creek Diversion Dam	Year Round	16 (normal years) 7 (dry years)
Lower Centerville Diversion Dam	6/1 - 9/14 9/15 - 5/31 12/15 – 10/31 11/1 - 12/14	40 (normal year) 30 (normal year) 40 (dry year) 10 (dry year)

Source: PG&E Co., 1999

Round Valley Reservoir (known locally as Snag Lake), the smaller of the two storage facilities, impounds up to a gross storage capacity of 1,196 af of water on the WBFR. Water released from the reservoir flows 13 miles in the WBFR before reaching the Hendricks Diversion, where it is diverted into the Hendricks Canal. The larger Philbrook Reservoir impounds up to a gross storage capacity of 5,009 af of water on Philbrook Creek, a tributary of the WBFR. Releases from Philbrook Reservoir pass down the natural channels of Philbrook Creek and into the WBFR about eight miles to Hendricks Diversion where the water is also diverted into the Hendricks Canal.

Water management at these reservoirs is controlled by FERC License Article 39 and subsequent FERC orders. The minimum instream flow release from Round Valley Reservoir is 0.5 cfs during normal years and 0.1 cfs during dry years. The minimum release from Philbrook Reservoir is two cfs, although when the inflow to the reservoir is less than 0.1 cfs, a minimum flow of at least 0.1 cfs may be released (FERC, 1980b).

A 1997 FERC Order also placed temperature restrictions on summer releases from Round Valley and Philbrook Reservoirs to enhance fish habitat. Water temperature criteria designed to protect cold-water salmon habitat in Butte Creek require that the discharges from Round Valley Reservoir be limited to the minimum flow whenever the average daily temperature of the discharge water exceeds 17°C. Similar water temperature limitations apply to Philbrook Reservoir. Minimum releases are required whenever the average daily temperature of the discharge water exceeds 18°C (FERC, 1997c). However, under FERC's August 1998 Order, a waiver of these requirements is possible if agreed to by USFWS, National Marine Fisheries Service, and CDFG (FERC, 1998b).

At Hendricks Diversion water is diverted through a series of canals to the Butte Creek drainage, and released into the WBFR to provide instream habitat. The minimum amounts of water released into the WBFR are 15 cfs in normal years and seven cfs in dry years, although spills are frequent during winter and spring runoff. In the summer months of dry years, Pacific Gas and Electric Company must release additional water (over the seven cfs requirement) to meet water supply delivery obligations to California Water Service at the Powers Canal (Coal Canyon Tailrace) (see discussion of Lime Saddle and Coal Canyon powerhouses). Up to 125 cfs of water is diverted at the dam into Hendricks Canal. The diverted water is conveyed 11.8 miles through a series of three canals (Hendricks, Toadtown, and Butte Creek), supplemented by diversions at small feeder streams along the canal lengths to the 188-af DeSabla Forebay. Hendricks Canal feeds into Toadtown Canal at the Toadtown Powerhouse (1.5 MW). The powerhouse operates at a normal maximum gross head of 185 feet (Powerhouse Physical Data Sheets 1998). Water passes from Hendricks Canal into a penstock, through Toadtown Powerhouse, and into Toadtown Canal. The powerhouse was sized by Pacific Gas and Electric Company to handle up to the 125-cfs maximum capacity of Hendricks Canal.

Another canal that combines with Toadtown Canal and feeds into the DeSabla Forebay is the Butte Creek Canal, which begins at the Butte Creek Diversion Dam, where Pacific Gas and Electric Company diverts up to 88.5 cfs of Butte Creek water into the 11.5-mile canal. Pacific Gas and Electric Company also makes releases into Butte Creek at the dam.

FERC License Article 39 stipulates minimum flows and also specifies releases at all major diversion points in the lower system. This article requires minimum flow releases into the ten mile DeSabla bypass reach of seven cfs during dry years or 16 cfs during normal years, although spills are frequent during winter and spring runoff.

Canal flow is supplemented by four feeder streams, the largest of which is Clear Creek. Maximum canal flow after Butte Canal and Toadtown Canal have merged can be up to 191 cfs into the DeSabla Forebay.

The DeSabla Forebay provides water for the DeSabla Powerhouse (18.5 MW) located on Butte Creek. Maximum gross head at the facility is 1,530 feet (Powerhouse Physical Data Sheets 1998). Tailrace water from the powerhouse is diverted from Butte Creek at the Lower Centerville Diversion Dam into the Lower Centerville Canal, where it flows 8 miles to the headworks of the Centerville Powerhouse (6.4 MW). One unit of the powerhouse operates at a normal maximum gross head of 590 feet, the other unit operates at 577 feet (Powerhouse Physical Data Sheets 1998). Up to 180 cfs may be diverted into the canal. Water is also released to Butte Creek at the Lower Centerville Diversion Dam into the six mile long Centerville bypass reach.

FERC License Article 39 specifies releases at the Centerville Diversion Dam. Pacific Gas and Electric Company is required to make minimum flow releases ranging from ten to 40 cfs, depending on season and water year type. During normal water years, a minimum release of 40 cfs is required from December 15 through October 31, and the release drops to 30 cfs between November 1 and December 14. During dry years, a minimum flow of 40 cfs is required from June 1 through September 14, and the remainder of the year the minimum flow release in Butte Creek can be lowered to ten cfs. Downstream reaches of the stream provide salmon habitat, and in past years Pacific Gas and Electric Company has informally agreed with CDFG not to exercise this reduction.

Toadtown, DeSabla and Centerville Powerhouses operate as baseload facilities, with their ability to respond to system energy needs restricted by the long length of the canals and the relatively small size of the reservoirs.

Water Delivery and Domestic Use. In addition to providing water for power production and instream beneficial uses, system water is used for some consumptive purposes. Some of the water in the DeSabla Forebay, for example, is also routed through the Upper Centerville Canal to holders of diversion rights, established through the Butte Creek adjudication, for irrigation and stock watering purposes (these rights are contingent upon continued use of the Upper Centerville Canal for power purposes). Releases to the Upper Centerville Canal typically range between two to three cfs. At the end of the canal, excess water empties into Helltown Ravine, where it can be added to the flow in the Lower Centerville Canal.

As described in Chapter 2, Pacific Gas and Electric Company has water rights in the DeSabla-Centerville System. There are additional contracts for water delivery or supply.

Water Quality. The beneficial uses associated with Butte Creek are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Butte Creek from the headwaters to Chico are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Cold Freshwater Habitat(COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Water quality studies performed in 1975 in the two higher elevation reservoirs and stream reaches revealed good water quality, well above the minimum levels necessary for aquatic life. While both reservoirs are nearly emptied during winter months, surface and bottom measurements of DO, temperature, and pH revealed excellent water quality (PG&E Co., 1982a). Similar results were found for the system streams and canals during the 1975 surveys (PG&E Co., 1982a), and in subsequent surveys conducted in 1982 for the construction of Toadtown Powerhouse. The 1985 License Application Amendment (PG&E Co., 1982a), containing additional information collected in 1984, indicated that existing water quality (based on monitoring for all years mentioned above) met EPA criteria and CVRWQCB objectives. The above findings describe a watershed with waters that are soft, low in alkalinity, and characterized by low total dissolved solids and high DO. Nutrients (nitrate and phosphate) concentrations are also low.

In addition, Pacific Gas and Electric Company is required under FERC License Article 19 to take reasonable measures to prevent water pollution, soil erosion, and stream sedimentation in the FERC-licensed water bodies (FERC 1975a). The effectiveness of such measures is typically reviewed by FERC during regular inspections.

In the past (1984, 1987-1993), Pacific Gas and Electric Company routinely monitored the water temperature in Butte Creek. Water temperatures in the Centerville bypass reach commonly exceeded 20°C during the period June through September, even when Pacific Gas and Electric Company released up to 40 cfs as required (FERC 1991b). Thus, the Cold Freshwater Habitat beneficial use is impacted, at least to some degree, by facility operations.

On September 8, 1992, Pacific Gas and Electric Company filed a temperature monitoring plan as required by FERC License Article 402. This article required that Pacific Gas and Electric Company conduct a two-year water temperature and stream flow monitoring study to determine if operational changes in the upper portion of the system might enhance water temperature below the Lower Centerville Diversion Dam for anadromous fish (FERC 1992b). This study was filed with FERC on January 31, 1994. Based on the results of this study, FERC ordered temperature release restrictions for Round Valley and Philbrook reservoirs and ordered Pacific Gas and Electric Company to investigate alternative water supplies for the downstream user, California Water Services Company (CWSC) (FERC 1993b). Pacific Gas and Electric Company states that water temperature studies conducted in 1992 and 1993 found the current mode of operation to be generally beneficial for salmon in Butte Creek (PG&E Co., 1994a).

In addition, a 1997 FERC Order placed temperature restrictions on summer releases from Round Valley and Philbrook reservoirs to further enhance fish habitat in Butte Creek (PG&E Co., 1994a). A 1998 FERC Order allows Pacific Gas and Electric Company more flexibility in meeting temperature requirements, depending on certain water year types and consultation with CDFG, NMFS and USFWS. Pacific Gas and Electric Company, in 1998, collected water temperature data in the WBFR and Butte Creek that will be utilized in determining future reservoir releases (i.e. release amounts, acceptable temperature, and location(s) for future monitoring).

Exhibit S of the FERC License Application was revised by FERC Order in 1984 (FERC, 1984). The revision was prepared following consultation with the National Marine Fisheries Service (NMFS), USFWS, and CDFG. It provides for continuous minimum flow releases, reimbursement for annual trout stocking, an operating regime for Philbrook Reservoir requiring a minimum pool volume, deer protection facilities in system canals, and other improvements. Pacific Gas and Electric Company has also installed monitoring and flow control measures to prevent canal washouts and overtopping, which can create erosion and sedimentation problems.

Groundwater. The DeSabla Centerville facilities do not use groundwater and little is known about the groundwater in the area.

Lime Saddle (Non-FERC)

The Drainage Basin and Water Sources. The Lime Saddle Powerhouse, located in Butte County, is part of the DeSabla Hydroelectric Generating Facility system, but is not licensed by FERC. The powerhouse is situated near the lower reaches of the WBFR, downstream of the DeSabla-Centerville System diversions and adjacent to the West Branch arm of Lake Oroville.

Hydroelectric Facilities. The powerhouse consists of the Lime Saddle Hydroelectric Generating Facility. The facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, canals and penstocks), as shown in Figure 4.3-5.

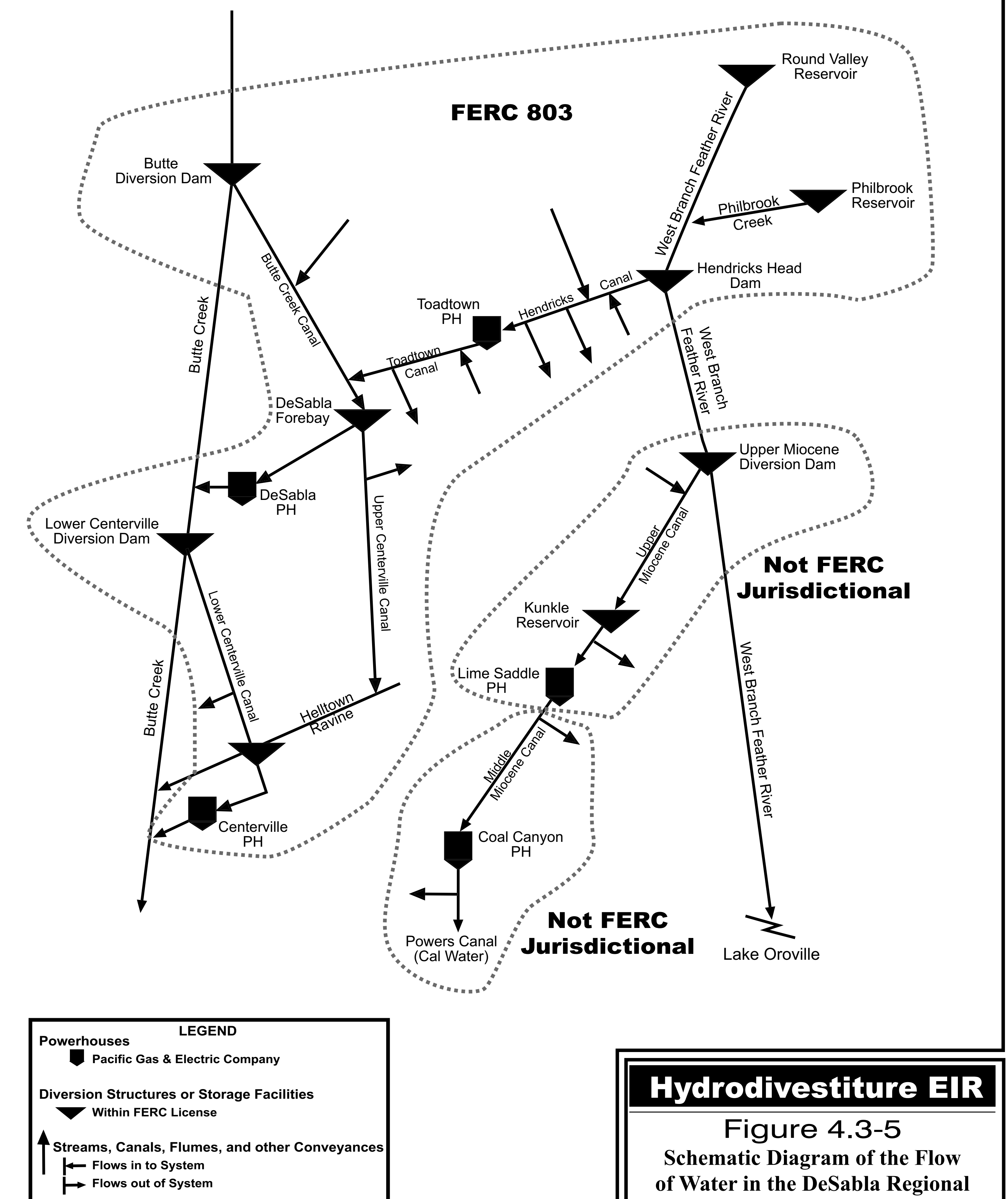
Water Management. Water used by the Lime Saddle Powerhouse (2 MW) is diverted from the WBFR at the Upper Miocene Diversion Dam into the Upper Miocene Canal. The Upper Miocene Canal has a maximum capacity of 65 cfs. The canal water flows to Kunkle Reservoir (154 af), where it is dropped through the penstock with a capacity of 87 cfs to the Lime Saddle Powerhouse. The powerhouse operates at a normal maximum gross head of 462 feet (Powerhouse Physical Data Sheets 1998). Pacific Gas and Electric Company makes a small release to the WBFR at Miocene Diversion Dam, but there is no regulatory requirement to do so.

The Middle Miocene Canal begins at the Lime Saddle Powerhouse tailrace. The Middle Miocene Canal has a typical flow of 45 cfs maximum to maintain delivery of water under contract to California Water Services Company. Therefore Lime Saddle Powerhouse is operated as a baseload facility, with the downstream (Middle Miocene) canal system capacity acting as the primary limiting factor. Its operation also must be coordinated with that of Coal Canyon Powerhouse (0.9 MW).

Water Delivery and Domestic Use. As described in Chapter 2, Pacific Gas and Electric Company has water rights at the Lime Saddle Powerhouse. There are additional contracts for water delivery or supply in the powerhouse.

Water Quality. The Sacramento-San Joaquin Basin Plan does not specifically identify beneficial uses for the WBFR. However, the Plan states that beneficial uses of an identified water body generally apply to its tributary streams. Therefore, the some or all of the beneficial uses identified for Lake Oroville are assumed to apply. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Lake Oroville are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-contact Water Recreation (REC-2)



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-5

Schematic Diagram of the Flow of Water in the DeSabla Regional Bundle (Butte Creek)

Aspen Environmental Group

- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Note that where both Cold Freshwater Habitat and Warm Freshwater Habitat are identified as beneficial uses, the more restrictive COLD conditions would apply.

Groundwater. The Lime Saddle facility does not use groundwater and little is known about the groundwater in the area.

Coal Canyon (Non-FERC)

The Drainage Basin and Water Sources. The Coal Canyon Powerhouse, located in Butte County, is part of the DeSabla Hydroelectric Generating Facility system, but is not licensed by FERC. The powerhouse is situated near the lower reaches of the WBFR, downstream of the DeSabla-Centerville System and six miles west of Lake Oroville. The powerhouse is operated in conjunction with Pacific Gas and Electric Company's Lime Saddle Powerhouse.

Hydroelectric Facilities. The powerhouse consists of the Coal Canyon Hydroelectric Generating Facility. The facility has a powerhouse, reservoir and/or associated appurtenant facilities (for example, canals and penstocks), as shown in Figure 4.3-5.

Water Management. Water use at the powerhouse is tied to the operation of the Lime Saddle powerhouse. The Lime Saddle Powerhouse tailrace water enters the Middle Miocene Canal at a maximum capacity of 45 cfs, where it is transported to the Coal Canyon Powerhouse. The powerhouse operates at a normal maximum gross head of 350 feet and has a normal operating capacity of 0.9 MW (Powerhouse Physical Data Sheets 1998). Tailrace water from the Coal Canyon Powerhouse flows into the Powers Canal, which is owned by CWSC.

Coal Canyon Powerhouse is operated as a baseload facility, and must be coordinated with the upstream Lime Saddle Powerhouse and downstream water delivery obligations.

Water Delivery and Domestic Use. The water from the Powers Canal is sold by Pacific Gas and Electric Company to CWSC under contractual obligation. This contractual obligation is up to 45 cfs. However, records indicate that CWSC actually uses 25-30 cfs. Pacific Gas and Electric Company also sells water in miner's inch measurements to various other parties between Lime Saddle and Coal Canyon Powerhouses.

As described in Chapter 2, Pacific Gas and Electric Company has water rights at the Coal Canyon Powerhouse. There are additional contracts for water delivery or supply.

Water Quality. The Sacramento-San Joaquin Basin Plan does not specifically identify beneficial uses for the WBFR. However, the Plan states that beneficial uses of an identified water body generally apply to its tributary streams. Therefore, the some or all of the beneficial uses identified for Lake Oroville are assumed to apply. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of Lake Oroville are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Where both Cold Freshwater Habitat and Warm Freshwater Habitat are identified as beneficial uses, the more restrictive COLD conditions would apply.

Groundwater. The Coal Canyon facility does not use groundwater and little is known about the groundwater in the area.

4.3.4.3 Drum Regional Bundle

The Drum Region includes four FERC licenses covering 15 powerhouses with a combined capacity of 218.2 MW. There are four separate bundles located in the Drum Region: North Yuba River, Potter Valley, South Yuba River, and Chili Bar (see Figures 2-23 and 2-24 in Chapter 2). The following sections describe water resources for each of Pacific Gas and Electric Company's FERC-licensed facilities in the Drum Region. Specifically, these sections describe each drainage basin and the location of the facilities, describe how water is used at each facility, describe the flow of water through the different facilities, and describe water diversion and use by other beneficial users. These sections also provide a description of water conveyance systems and capacities, as well as maximum powerhouse capacity.

When applicable, the unique water use constraints, such as physical capacity constraints, storage constraints, and regulatory restrictions (e.g., instream flow release requirements) included in FERC licenses, are discussed for each facility. Schematic diagrams depict the flow of water.

Regional Setting

The Drum Region consists of 14 powerhouses located in Nevada, Placer, and El Dorado counties, in the Sierra Nevada mountains, and one powerhouse in Mendocino County, located in the Coast Range of northern California about 120 miles west of the Sierra Nevada. Five rivers feed 39 dams. The headwaters of the Sierran rivers extend east to Donner Summit. Its powerhouses include the two newest, Newcastle and Wise 2, built in 1986, and have a total generating capacity of 218 MW. The general layout of the Drum facilities and the major hydrographic features within this regional bundle are shown in Figures 2-21 and 2-22 in Chapter 2.

The Yuba River watershed (FERC 2310) drains 1108 square miles at the Narrows powerhouses. It is located in portions of Yuba, Sierra, and Nevada counties. Precipitation in the Yuba River basin ranges from 32 inches at Englebright reservoir to over 80 inches at the Sierra Nevada crest. Most runoff occurs in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season. Flow in the Yuba River at the Narrows powerhouses is primarily regulated by storage in New Bullards Bar Reservoir and Englebright Reservoir which are owned and operated by Yuba County Water Agency and the U.S. Army Corps of Engineers respectively. Other significant reservoirs include Jackson Meadows and Bowman Lake, operated by NID to divert water to the South Yuba/Bear River facilities. OWID diverts water from the Slate Creek tributary to the Feather River basin. Power generation at the Narrows powerhouses is essentially dependent on storage releases determined by these agencies.

The South Yuba/Bear River watersheds (FERC 2310) have a watershed area of 305 square miles at the Wise Powerhouse. These watersheds are located in Nevada and Placer counties. Mean annual precipitation ranges from 36 inches at the Wise Powerhouse near Auburn, to 70 inches at Lake Spaulding, to over 85 inches on the Sierra Nevada crest. Most runoff occurs in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season. The system consists of twelve powerhouses with a capacity of 904,000 megawatt hours and 35 reservoirs with a storage capacity of 151,300 acre feet. The principal storage reservoirs are Lake Fordyce, capacity 45,900 acre feet, and Lake Spaulding, capacity 74,800 af, which store flow from the Fordyce Creek tributary and South Yuba River and divert much of it to the Bear River.

The South Fork American River watershed (FERC 2155) has a drainage area of 598 square miles at the Chili Bar powerhouse. The South Fork American watershed is located in El Dorado County. Precipitation for the South Fork watershed ranges from 30 inches near Placerville to over 80 inches on the Sierra Nevada Crest. Mean annual runoff is 1,370 cfs, with most runoff occurring in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season. The Chili Bar Powerhouse is essentially run-of-the-river since it is dependent on releases from storage facilities owned and operated by the Sacramento Municipal Utility District.

The Eel River watershed (FERC 0077) has a drainage area of 289 square miles at Lake Pillsbury. The watershed is located in portions of Lake, Mendocino, and Humboldt counties. Precipitation in the Eel River watershed ranges from 44 inches at Potter Valley Powerhouse to 75 inches at the highest elevations. The flow regime at the Eel River is dominated by winter rainfall instead of snowmelt with maximum runoff in February. Lake Pillsbury has a storage capacity of 80,600 af and serves the Potter Valley Powerhouse.

Local Regulations and Policies

Refer to Section 4.3.2.

Bundle 9: North Yuba River

The North Yuba River Bundle consists of FERC No. 1403 (the Narrows 1 Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

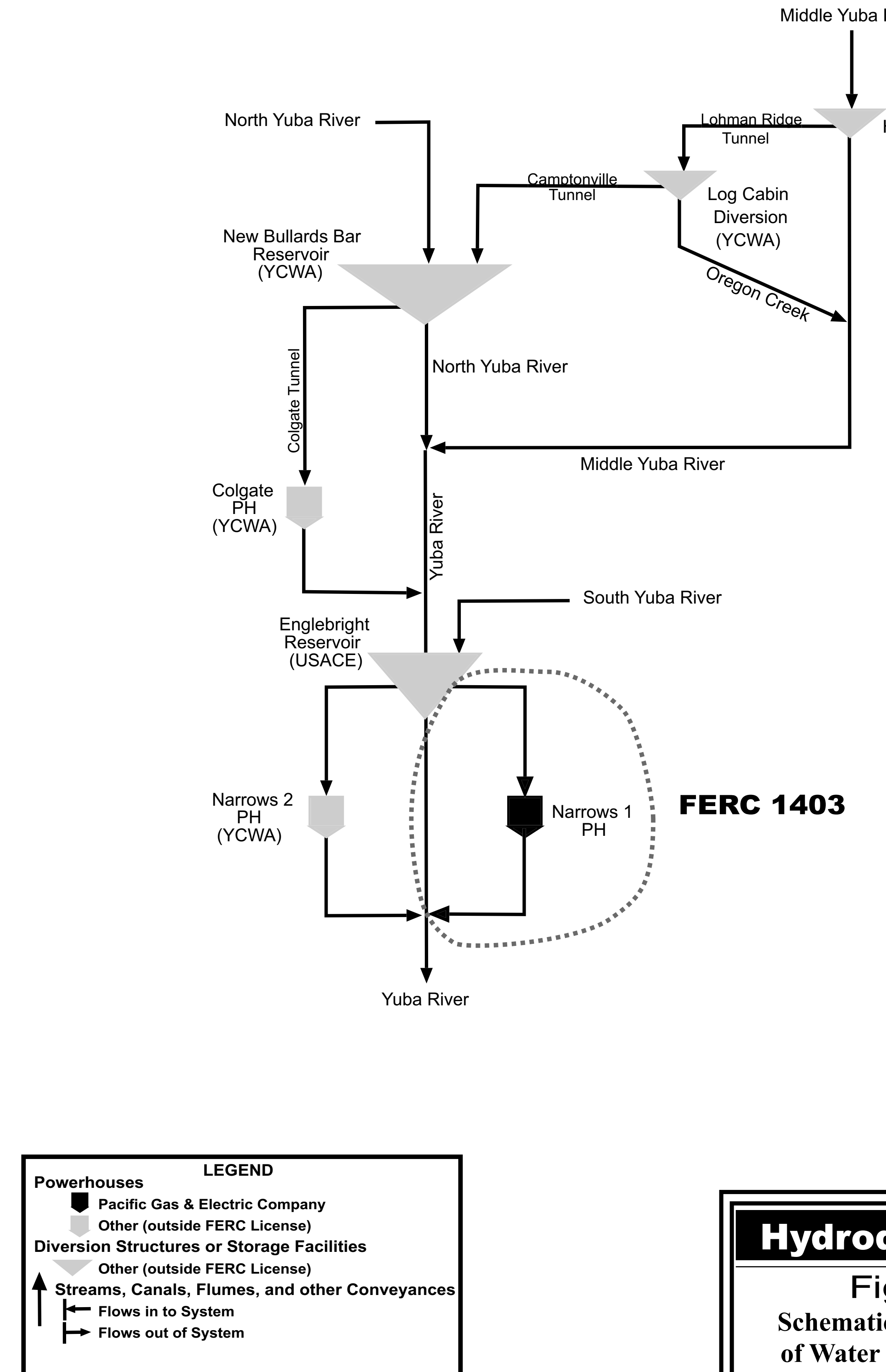
Narrows (FERC 1403)

The Drainage Basin and Sources of Water. The Narrows System lies within the Yuba River basin, in Nevada County, downstream of the confluence of the South Fork, Middle Fork, and North Fork Yuba River, and approximately 25 miles upstream of the confluence of the Yuba River with the Feather River. The drainage area within the Yuba River basin that is used by the system is 1,108 square miles, as measured directly below Englebright Dam. (USGS, 1997). A majority of the water from the South Yuba basin is diverted to the Bear and American Rivers by upstream water facilities owned by Pacific Gas and Electric Company and NID. NID diverts water from the Middle Fork Yuba River basin to the South Fork Yuba basin and the Bear and American Rivers. Water storage and diversion facilities owned and operated by the Yuba County Water Agency (YCWA), and the USACE regulate water use within the three forks of the Yuba River by releases from USACE's Englebright Reservoir.

Hydroelectric Facilities. The Narrows System consists of the Narrows Hydroelectric Generating Facility. The facility has a powerhouse and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-6.

Water Management. Water use in the system begins with releases made by the YCWA from their New Bullards Bar Reservoir, located upstream of Englebright Reservoir, on the North Fork Yuba River. The released water passes through the YCWA Colgate Powerhouse, then merges with water in the Middle and South Forks of the Yuba River before flowing into Englebright Reservoir. Pacific Gas and Electric Company diverts water from the reservoir into a 1,060-foot-long tunnel, which delivers the water to a 730-cfs penstock, and through the Narrows Powerhouse (12.0 MW). Water discharged from the powerhouse enters a tunnel that empties into the Yuba River. Normal maximum gross head at the facility is 240 feet (PG&E Co., 1998E).

The Narrows System operates as a baseload facility, primarily due to constraints on the rate of change of flows in the river downstream of the powerhouse. FERC mandated minimum flows are summarized in Table 4.3-18 below and further described in the following paragraphs.



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-6

Schematic Diagram of the Flow of Water in the Drum Regional Bundle (North Yuba River)

Aspen Environmental Group

Table 4.3-18 Minimum Releases Associated with the Narrows 1 Powerhouse

Time Period	Minimum Release (cfs)
October 1 - March 31	700
April 1 -April 30	1,000
May 1 - May 31	2,000
June 1 -June 30	1,500
July 1 – September 30	450

Source: PG&E Co., 1999

Article 402 of Pacific Gas and Electric Company's 1989 FERC license requires that Pacific Gas and Electric Company supplement YCWA's releases to meet minimum flow requirements of 450-2,000 cfs at a gage near Smartsville (FERC, 1993a). In addition, Pacific Gas and Electric Company has a storage agreement with the Sacramento District, Corps of Engineers that fulfills Articles 101 and 102 of the FERC license (PG&E Co., 1994b).

The minimum release requirements for Pacific Gas and Electric Company's Narrows Facility were established to supplement releases from YCWA's Narrows 2 facility located just below Englebright Dam slightly upstream of Pacific Gas and Electric Company's Narrows 1 Powerhouse. The required minimum flows vary seasonally:

Ramping rate limits are imposed by Article 405 of Pacific Gas and Electric Company's FERC license in order to minimize negative effects of downstream flow fluctuations caused by hydropower generation (particularly peaking operations) (FERC, 1994c). These limits (as well as minimum flows) are coordinated with YCWA's operation of the Colgate and Narrows 2 Powerhouses. A ramping rate constraint requires that whenever the combined flows from Narrows 1 and 2 are less than 700 cfs, the rate of change of flow is limited to 200 cfs per hour. The ramping rate does not apply when Englebright Reservoir is spilling, or when either powerhouse has an equipment malfunction. If the Narrows 2 Powerhouse is shutdown for maintenance, the Narrows 1 Powerhouse must maintain the above flows or 600 cfs, whichever is less. The license also contains a limited reopener provision to alter the minimum flow requirements if the contractual ability to dispatch releases from New Bullards Bar Reservoir terminates or expires.

The presence of anadromous fish in the Yuba River below Englebright Reservoir that have recently been listed as threatened species can, at times, further constrain operations of Narrows 1 and 2 in addition to the FERC requirements. To address the possibility of any impacts to anadromous fish related to FERC-licensed facilities, FERC has designated Pacific Gas and Electric Company as its non-Federal representative in a Section 7 consultation under the Endangered Species Act (FERC, 1999a).

Water Quality. The beneficial uses associated with the Yuba River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water

Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Yuba River from Englebright Dam to the Feather River are:

- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Where both Cold Freshwater Habitat and Warm Freshwater Habitat are identified as beneficial uses, the more restrictive COLD conditions would apply.

Pacific Gas and Electric Company states that water flowing through the system is of good quality, suitable for all beneficial uses identified by the CVRWQCB. Due to the large volume of cold water impounded by the upstream New Bullards Bar Dam, operation of the reservoir provides a relatively stable inflow of cool water to Englebright Reservoir during summer months. Since Englebright Reservoir has a short retention time, water released into the Yuba River is cool, generally remaining below 21°C during summer months. Staff from the SWRCB note that the Basin Plan goal is protection of all beneficial uses and that optimum temperatures for cold water fisheries are between 15°C and 19°C and that exceedance of a 20°C temperature threshold would negatively impact Cold Freshwater Habitat (SWRCB, 2000). Dissolved oxygen (DO) concentrations range from 9.5 to 12.8 mg/L, well above minimum standards recommended by the EPA and the CVRWQCB for the protection for aquatic life. Total dissolved solids and total suspended solids are generally low, ranging from 40-85 mg/L and 0-6 mg/L, respectively (PG&E Co., 1986c), and pH levels are near neutral.

FERC License Article 19 requires Pacific Gas and Electric Company to take reasonable measures to prevent stream sedimentation and any other form of water pollution (FERC, 1975). In addition, Pacific Gas and Electric Company has an agreement with the Sacramento Corps of Engineers to operate and maintain the facility to prevent any degradation of water quality (PG&E Co., 1994c).

Groundwater. Little information was collected about the groundwater within the North Yuba River basin as the facility does not use it. However, groundwater in the area is expected to be relatively soft and of high quality. If originating from carbonate rocks, the groundwater would exhibit a high mineral content. It is also expected to be high in DO and weakly stratified with respect to temperature.

Bundle 10: Potter Valley

The Potter Valley Bundle consists of FERC No. 0077 (the Potter Valley Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

Potter Valley (FERC 0077)

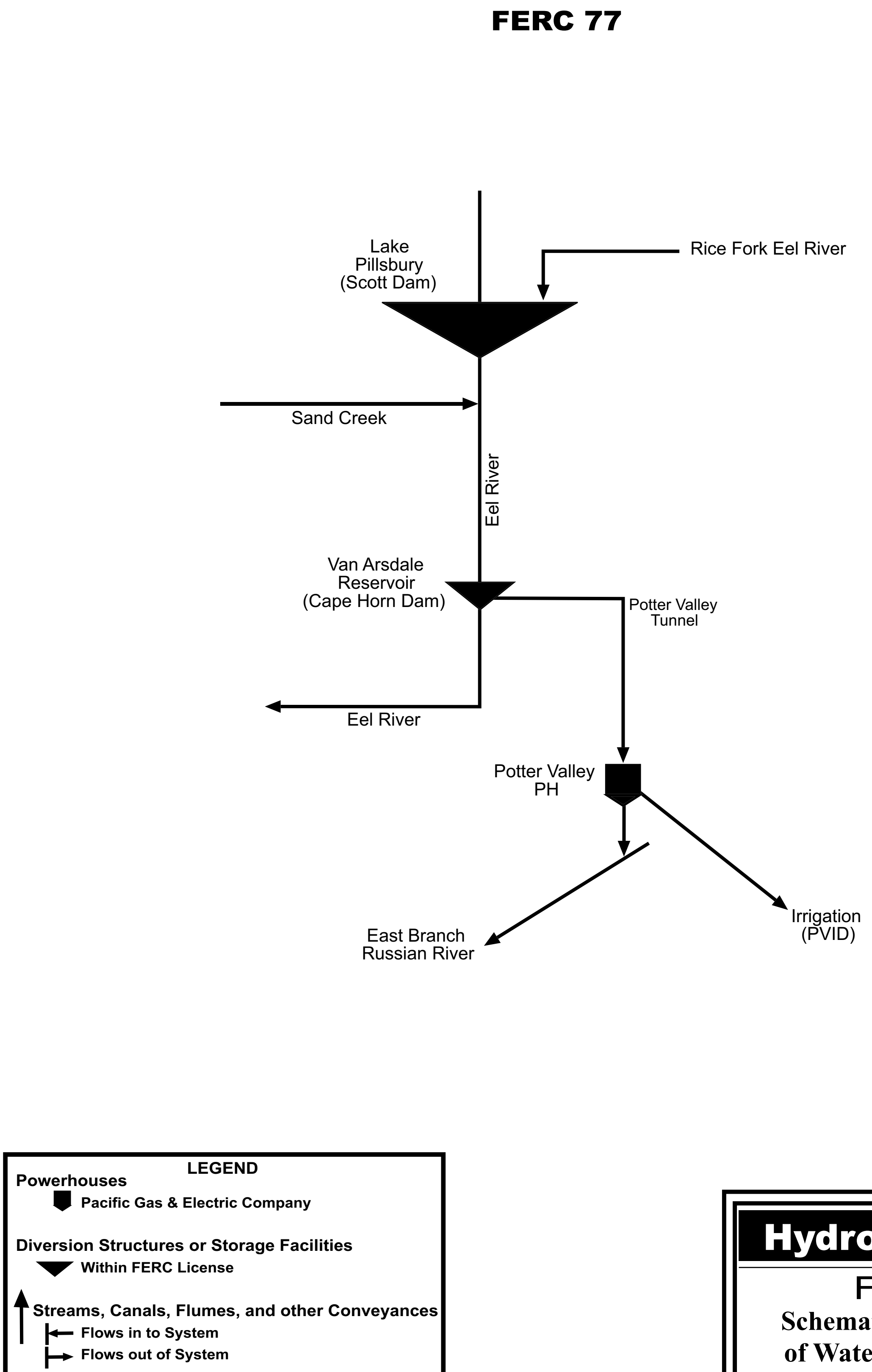
The Drainage Basin and Water Sources. The Potter Valley System is located on the Eel River, a coastal river in northern California that lies in Lake, Mendocino, and Humboldt counties. The headwaters of the Eel River originate in the western slopes of Goat Mountain in Mendocino County at an elevation of approximately 6,121 feet. The drainage area within the Eel River watershed used by the system is 349 square miles, as measured directly below the Cape Horn Dam (USGS, 1997).

Hydroelectric Facilities. The asset consists of the Potter Valley Hydroelectric Generating Facility. The facility has one powerhouse, reservoirs, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-7.

Water Management. Two reservoirs on the Eel River store and regulate water for the Potter Valley Powerhouse (9.2 MW): Lake Pillsbury and Van Arsdale Reservoir. Lake Pillsbury has a usable storage capacity of 80,556 af. The drainage area above the lake is 289 square miles. Water is released from Lake Pillsbury and transits down the Eel River approximately 12 miles to Van Arsdale Reservoir. Average annual discharge into Van Arsdale Reservoir from Lake Pillsbury is 555 cfs. Van Arsdale Reservoir has a usable storage capacity of 390 af and serves as forebay to the powerhouse. Water is diverted from the forebay into the Potter Valley Tunnel, which leads to two penstocks that deliver water to the powerhouse. Average annual flow to the penstocks is 202 cfs. Normal maximum gross head is 478 feet (PG&E Co., 1998F).

Minimum flow releases required for anadromous fish migration often prevent the diversion of the maximum capacity through the intake tunnel. In addition, lake storage management of Lake Pillsbury for recreation purposes during the summer places limitations on releases made from Scott Dam upstream, which in turn limits available flow for diversion. Average annual flow delivered to the Russian River basin from the powerhouse is 172 cfs. Water in Van Arsdale Reservoir not diverted for power production is released to the Eel River. Since Van Arsdale Reservoir is partially filled with sediment and minimum flow releases into the Eel River are required year round, the reservoir functions primarily as a diversion dam; however, during the summer when flashboards increase storage, the reservoir serves as a forebay by filling overnight for diversion and power production the following day.

Minimum flows in the Eel River downstream of the Potter Valley System were established by a settlement agreement between Pacific Gas and Electric Company and several other parties, and incorporated into Article 38 of the 1983 FERC license (FERC, 1983a). In March 1998, Pacific Gas and Electric Company filed with FERC a joint Pacific Gas and Electric Company-resource



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-7

Schematic Diagram of the Flow of Water in the Drum Regional Bundle (Eel and East Fork of Russian River)

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agency proposal for a new flow schedule that will decrease average annual water yield to the East Branch Russian River by 15 percent to meet goals related to the restoration of the anadromous fishery on the Eel River.

The license defines normal, dry, and critical water years based on inflows to Lake Pillsbury, and also identifies the volume of water that is reserved for release at the discretion of the CDFG. The minimum releases are shown below (USGS, 1997):

Table 4.3-19 Minimum Releases Associated with the Potter Valley System

		Water Year Type		
	Time of Year	Normal	Dry	Critical
East Branch Russian River	September 16 – May 14	35 cfs	35 cfs	20 cfs
	May 15 - September 15	75 cfs	40 cfs	20 cfs
Eel River below Scott Dam	December 1 – May 31	100 cfs	40 cfs	20 cfs
	June 1 – November 30	60 cfs	40 cfs	20 cfs

Source: PG&E Co., 1999

Water Delivery and Domestic Use. Powerhouse tailrace water is supplied to the Potter Valley Irrigation District ditches to meet contractual obligations and is also released, via the powerhouse canal, to the East Branch Russian River.

As discussed above and described in Chapter 2, Pacific Gas and Electric Company has water rights associated with the Potter Valley System. There are additional contracts for water delivery or supply associated with the facilities.

Water Quality. The beneficial uses associated with the Eel River are summarized in the 1998 Basin Plan for the North Coast region compiled by the Regional Water Quality Control Board, North Coast Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Eel River are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Industrial Service Supply (IND)
- Groundwater Recharge (GWR)
- Navigation (NAV)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Commercial and Sport Fishing (COMM)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Rare, Threatened, or Endangered Species (RARE)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)
- Estuarine Habitat (EST)

- Aquaculture (AQUA)

Listed beneficial uses for the Russian River are the same, with the addition of industrial process supply (PROC). It should be noted that the North Coast basin plan does not subdivide the Eel or Russian Rivers for the purposes of defining beneficial uses; consequently many of the uses listed may not apply to the project area. Note also that minimum flows for the protection of anadromous fish (RARE) have not yet been resolved.

A highly variable hydrology, unstable geology, steep terrain, and historic land use practices have combined to create a river system with high rates of erosion and sediment loads. Average suspended sediment transport for the Eel River basin has been estimated at 31.5 million tons per year, the highest per square mile of watershed load in the United States (Brown and Ritter 1974). Sediment production in the vicinity of the Potter Valley system is lower than that for the river as a whole. Sediment production between 1958 and 1976 has been estimated for the upper Eel River at 2,383 tons per square mile (Corps 1980). Within the system, Lake Pillsbury acts as a sediment trap. However, heavy sediment input from Soda Creek just below Scott Dam helps minimize sediment starvation problems. Tomki Creek, a major tributary to the upper Eel River, whose confluence is approximately three miles downstream of Cape Horn Dam, was listed as an impaired waterbody under Section 303(d) of the Clean Water Act by the USEPA in 1998 because of nonpoint source sediment and siltation (USEPA 1998). The Upper Main Fork Eel River and the entire Russian River watershed are also listed under CWA 303(d) for sedimentation and siltation (USEPA, 1998).

At Van Arsdale Reservoir, suspended sediment concentrations have been recorded at levels up to 3,540 mg/L. Approximately 35 percent of the suspended sediment load is silt (FERC, 1978). Turbidity levels in the winter have been measured at 210 Jackson Turbidity Units (JTU), whereas summer turbidity levels drop to near zero (ISGS, 1997). Turbidity measurements between Lake Pillsbury and Van Arsdale Reservoir by Pacific Gas and Electric Company ranged from 1.9 nephelometer turbidity units (NTU) in August 1982 to 38 NTUs in May 1982 (Creek, Et al, 1984).

Water quality in Lake Pillsbury is degraded on an annual basis due to increased turbidity following the first major winter storm. The lake remains turbid throughout the winter due to the nature of the clay material running off from the watershed and high pH chemical reactions occurring in the lake. The primary method of control is improvement in conditions higher up in the watershed in areas that are out of Pacific Gas and Electric Company's control.

Lake Pillsbury is listed as an impaired water body under Section 303(d) of the Federal Clean Water Act due to the high levels of mercury found in fish (USEPA 1998). Mercury is a naturally occurring heavy metal. Cinnabar ores are naturally rich in mercury and are also very common in the California Coast Range (USEPA 1999). Micro-organisms convert this mercury into methylmercury, a particularly toxic form of mercury. Methylmercury enters the food web when it is taken in by benthic organisms which are consumed by larger animals and eventually by fish.

During this process, methylmercury accumulates in the predators at the upper levels (USEPA 1999). As part of the Toxic Substance Monitoring Program, tissue samples were collected and analyzed from fish in Lake Pillsbury over a period of years. Results of this work are muscle tissue concentrations that exceed the 1 ppm action level established by the U.S. Food and Drug Administration (USEPA 1999).

Water temperatures on the surface of Lake Pillsbury and at the fish ladder have been recorded near 24°C in late July. Temperatures in the Eel River upstream of Van Arsdale Reservoir generally do not exceed 18 to 20°C. Hydrogen ion concentration, or pH, averages about 8.0 in the Eel River. Water hardness averages about 70 mg/l, indicating that the water is moderately hard.

Seasonal fluctuations of discharge patterns and air temperatures combine to create the temperature regimes of the Eel River. Extensive temperature monitoring has been conducted on the upper Eel River (SEC 1998; VTN 1982; BEAK 1986). During periods of relatively high discharges and shorter day length, typically winter and early spring, water temperatures are relatively uniform within the system, e.g., approximately 6 to 7°C in January and February (SEC 1998). Increasing day length and decreasing flows in the spring create warming trends apparent in data recorded over the years. Because Lake Pillsbury is stratified during the summer and releases from Scott Dam are made through the needle valve at the base of the dam, water temperatures in the main stem below Scott Dam tend to be relatively cool through the summer months. The seasonal range of water temperatures below Scott Dam (historical monthly mean data) range from the lows mentioned previously to approximately 19°C in September (SEC 1998). This relatively cool water travels through the reach to Cape Horn Dam, warming as it progresses downstream. By the time it reaches Van Arsdale Reservoir, it has warmed significantly. Historical monthly mean data for the Eel River at Cape Horn Dam range from the lows mentioned previously to just over 20°C in July (SEC 1998). Temperature impacts due to facility operations are considered a controllable factor in the Basin Plans (SWRCB, 2000).

During the summer months, most of the water is diverted to the powerhouse for electrical generation. However, by the time this water is diverted, the potential for downstream cooling (below Cape Horn Dam) appears minimal (SEC 1998). Water temperatures in the tributaries generally reflect their smaller size and lower stream flows. However, water temperatures in the tributaries may remain cool because of heavy riparian shading and decreased exposure to solar heating.

FERC License Article 19 requires Pacific Gas and Electric Company to take measures to prevent stream sedimentation and any other form of water pollution (FERC, 1975b).

Groundwater. No information was collected about groundwater in the upper Eel River Basin and Potter Valley as the Potter Valley facility does not use groundwater.

Bundle 11: South Yuba River

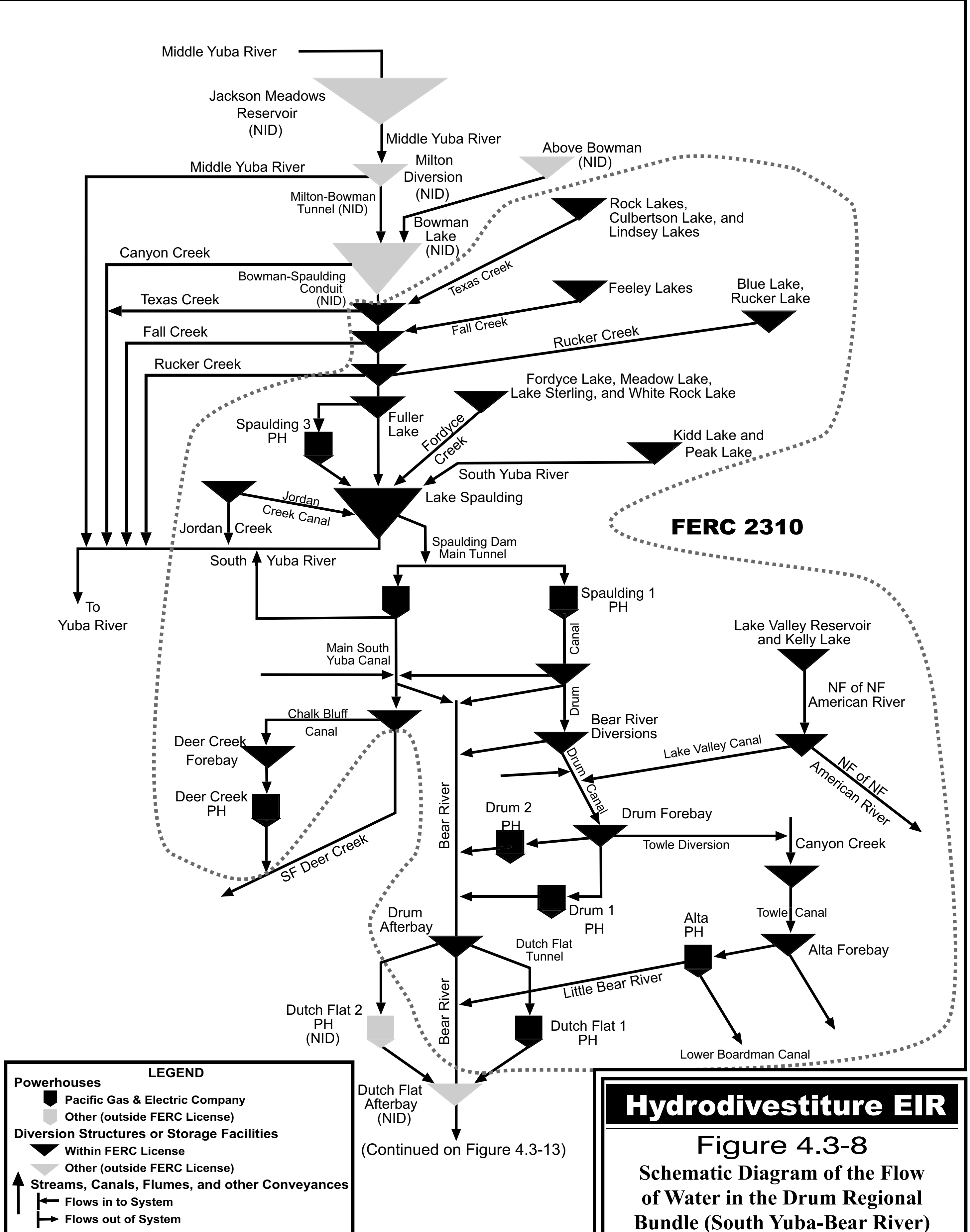
The South Yuba River Bundle consists of FERC No. 2310 (the Spaulding 1, 2, and 3, Deer Creek, Drum 1 and 2, Dutch Flat 1, Alta, Halsey, Wise 1 and 2, and Newcastle Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 2310.

Drum-Spaulding (FERC 2310)

The Drainage Basin and Water Sources. The Drum-Spaulding System extends from the crest of the central Sierra Nevada to Auburn, California, covering an elevational range from 300 to 8,000 feet. Only a small portion of the headwaters of the North Fork American River is part of this system. The system consists of an extensive network of hydraulically linked facilities located within the Yuba River, Bear River, Deer Creek, and American River basins, including multiple interbasin water transfers. The Yuba and Bear rivers originate on the west slope of the Sierra Nevada. The South Fork Yuba River begins near Soda Springs (6,768 feet elevation) in Nevada County, although headwaters reach as high as 8,000 feet near White Rock Reservoir. The Bear River originates near the 5,243-foot Emigrant Gap in Placer County. The combined drainage basins encompass approximately 305 square miles as measured at Wise Forebay (PG&E Co., 1996d).

Hydroelectric Facilities. The Drum-Spaulding System is located in the Central Sierras along the Highway 80 corridor. It begins on the South Yuba River near Donner Summit and ends at Folsom Lake on the American River. In between these two locations water is transported through the Bear River watershed, as well as diverted from the American River watershed. The asset consists of 12 powerhouses: Spaulding 1, 2, and Spaulding 3, Drum 1 and 2, Deer Creek, Dutch Flat 1, Alta, Halsey, Wise and Wise 2, and Newcastle, and provides an average annual output of 904,000 megawatt hours of energy. In order to supply and deliver the water to the powerhouses, there are 35 storage, diversion, and regulating reservoirs with a designed usable capacity of 151,265 af, as well as a water conveyance system which includes 64.76 miles of canal, 9.92 miles of flume, 9.88 miles of tunnel, and 3.53 miles of pipe and penstock. Figures 4.3-8 and 4.3-9 show a schematic of the system.

Water Management. While the operation of the Drum-Spaulding System is based on the primary purpose of power generation, its operation is also heavily influenced by contracts and agreements between Pacific Gas and Electric Company and other water users in the drainage basin. The various contracts and agreements are described below. NID owns and operates the Yuba-Bear Assets, which use water in the Middle and South Fork Yuba River, North Fork American River, Deer Creek, and the Bear River. The NID Yuba-Bear Assets represent an extensive system of reservoirs, powerhouses, and canals that are commingled with the Drum-Spaulding System through a combination of physical structures and complex water rights and operational agreements. The three NID powerhouses, Dutch Flat 2, Chicago Park, and Rollins, are dispatched by Pacific Gas and Electric Company under a power purchase.



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-8

Schematic Diagram of the Flow of Water in the Drum Regional Bundle (South Yuba-Bear River)

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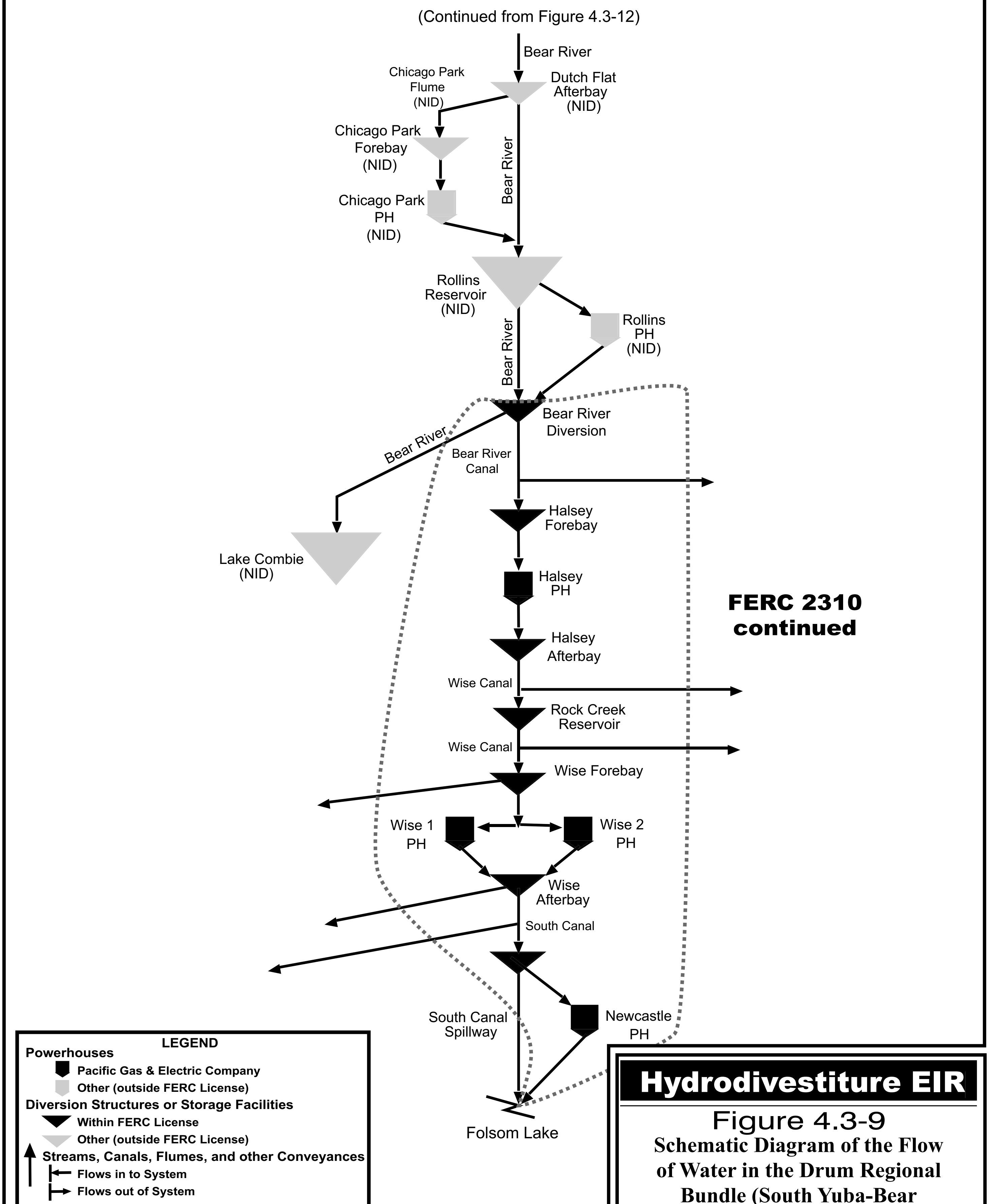

Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-9

Schematic Diagram of the Flow of Water in the Drum Regional Bundle (South Yuba-Bear River continued)

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Separate water contracts with the PCWA also allow for the sale of irrigation and domestic water in the downstream end of the system from numerous delivery points. Operation of the Drum-Spaulding System is highly influenced by the irrigation demand of these two agencies (NID and PCWA).

The Drum-Spaulding System is composed of 12 separate hydroelectric generating facilities. Each facility is discussed in more detail below, in order of most upstream to most downstream.

Spaulding 3 Powerhouse. The Spaulding 3 Powerhouse (5.8 MW), constructed in 1929, is located on the northeast shore of Lake Spaulding. The powerhouse is supplied via the Bowman-Spaulding Canal, and tailrace water discharges directly into Lake Spaulding. The Bowman-Spaulding Canal is the primary means through which NID delivers the water from its reservoirs into the Drum-Spaulding System. The Bowman-Spaulding Canal begins at NID's Bowman Lake and travels 14 miles before reaching Spaulding 3 Powerhouse. Prior to reaching the Spaulding 3 Powerhouse, the water passes through the Bowman Powerhouse, a qualifying facility (QF) owned by the Nevada Power Authority (NPA). (NPA is a joint powers authority formed by NID, Nevada City, and Nevada County. Pacific Gas and Electric Company currently purchases all power generated from the Bowman Powerhouse under an Interim Standard Offer #4 power purchase agreement [Bowman ISO #4].) Additional water from the Drum-Spaulding's Texas-Fall Creek system (a series of ten small lakes) is also diverted into the Bowman-Spaulding Canal during the fall. Together, theses two sources provide an average annual flow of 214 cfs to Spaulding 3 Powerhouse. The maximum capacity of the Spaulding 3 Powerhouse is 270 cfs. Normal maximum gross head at the facility is 318 feet (PG&E Co., 1998d).

FERC License Article 39 requires that minimum flows must be maintained in the creeks below the dams on the Texas-Fall Creek Lakes (PG&E Co., 1980). These are listed below:

Table 4.3-20 Minimum Releases Associated with the Spaulding 3 Powerhouse

Facility	Time Period	Minimum Release (cfs)
Upper Rock Lake	7/1-9/30	0.25
Lower Rock Lake	7/1-9/30	0.25
Culbertson Lake	Year Round	0.75
Middle Lindsey Lake	7/1-9/30	0.25
Lower Lindsey Lake	Year Round	0.50
Feeley Lake	Year Round	0.50
Carr Lake	Year Round	0.50
Blue Lake	Year Round	0.50
Rucker Lake	Year Round	0.50

Source: PG&E Co., 1999

In addition, FERC License Article 40 stipulates reservoir levels at 14 of the system reservoirs. Included are maximum storage levels, minimum storage levels, and maintenance of maximum possible summertime water levels. Finally, License Article 38 requires that Pacific Gas and Electric

Company operate the facilities to avoid increased releases from reservoirs during flood periods (PG&E Co., 1980).

Spaulding 1 and 2 Powerhouses. Lake Spaulding serves as the primary water regulation and storage reservoir for the upper portion of the Drum-Spaulding System. Lake Spaulding has a storage capacity of 74,773 af. In addition to the water discharged from the Spaulding 3 Powerhouse, the South Yuba River and Fordyce Creek drainage areas supply water to Lake Spaulding. As part of the Drum-Spaulding System, Pacific Gas and Electric Company operates four lakes on the Fordyce Creek drainage (White Rock, Sterling, Meadow, and Fordyce lakes) and three lakes on the South Yuba drainage (Upper and Lower Peak and Kidd lakes). The largest of these is the 49,903-af gross storage capacity Lake Fordyce. Average annual flow into Lake Spaulding from the South Fork Yuba River and Fordyce Creek is 198 cfs and 131 cfs, respectively. The drainage area contributing water to Lake Spaulding, and hence to Spaulding 1 and 2 Powerhouses, is 189.7 square miles.

Table 4.3-21 Minimum Releases Associated with the Spaulding 1 and 2 Powerhouses

Facility	Time Period	Minimum Release (cfs)
Fordyce Lake flowing into Fordyce Creek	Year round	5 or 3
South Fork Yuba River below Spaulding 2 Powerhouse	Year Round	1
South Fork Yuba River from Langs Crossing (1 mi downstream from Spaulding 2 PH	Year Round	2
Bear River 0.1 miles below DFG Bear River fish planting base	Year Round	5
Bear River below Upper Boardman Canal Diversion Dam	Year Round	1 or NF

Source: PG&E Co., 1999

The minimum flow requirement in Fordyce Creek, as established by Article 39 of the FERC license, is five cfs all year, although 3 cfs may be permitted when Fordyce Lake is at its lowest winter storage level of 3,000 af.

Located immediately below Lake Spaulding are Spaulding 1 and 2 Powerhouses (11.4 MW). A 963-foot-long tunnel and penstock convey water from Lake Spaulding to the Spaulding 1 Powerhouse. The maximum capacity of the powerhouse is 550 cfs, and the normal maximum gross head is 197 feet, depending on the water level of Lake Spaulding (PG&E CO., 1998d). Water discharging from the powerhouse enters the Drum Canal, which is located in the headwaters of the Bear River watershed. In addition to the water passing through the turbine (512 cfs mean annual flow from 1965-1996), water can be bypassed around the turbine for a total discharge into the Drum Canal of approximately 850 cfs. The water in the Drum Canal is the primary supply for the lower portion of the Drum-Spaulding System. In addition to supplying water to Spaulding 1 Powerhouse, the water from Lake Spaulding is also released through Spaulding 2 Powerhouse. The maximum capacity of the powerhouse is 200 cfs, and the normal maximum gross head is 344 feet, depending on the water level of Lake Spaulding (PG&E Co., 1998d). Water discharging from the powerhouse enters the `South Yuba Canal, which carries water in an elevated flume or lined canal for approximately 20 miles into the Deer Creek watershed. This water supplies Deer Creek Powerhouse and is then diverted by NID for domestic and irrigation deliveries. The South Yuba Canal has a capacity of 145 cfs at the upper end and a capacity of 107 cfs on the lower end.

Excess water from the South Yuba Canal is spilled to the Bear River and is used to make up the FERC license required minimum flow of five cfs in the Bear River. FERC License Article 39 requires two additional minimum flows: one cfs in the South Yuba River below the Spaulding 2 Powerhouse and five cfs at Langs Crossing (located 1 mile downstream) (PG& E Co., 1980).

Deer Creek Powerhouse. Deer Creek Powerhouse (5.7 MW), constructed in 1908, is supplied by water via the South Yuba Canal, which, as described above, is fed from the tailrace water at Spaulding 2 Powerhouse. The South Yuba Canal, with a capacity of 145 cfs (mean annual flow from 1965-1986 of 85.4 cfs), runs for 15.7 miles before entering a tunnel where it emerges as the Chalk Bluff Canal, which runs for another 3.2 miles before discharging into the Deer Creek Forebay (16 af). The Chalk Bluff Canal has a capacity of 107 cfs. The excess water between the South Yuba Canal and the Chalk Bluff Canal is spilled to the Bear River where it is diverted downstream for use through the Dutch Flat 1 (Pacific Gas and Electric Company) and Dutch Flat 2 (NID) Powerhouses. The maximum capacity of the Dutch Flat 1 Powerhouse is 490 cfs, and the normal maximum gross head is 837 feet (PG&E Co., 1998d). Water from the Deer Creek Forebay is discharged via a 110-cfs capacity penstock through Deer Creek Powerhouse and into Deer Creek. This water is then diverted a short distance downstream by NID, supplying the main bulk of irrigation and domestic water supply for the Nevada City and Grass Valley areas.

Drum 1 and 2 and Alta Powerhouses. In addition to the water entering the Drum Canal from Spaulding 1 Powerhouse, additional water is diverted to the Drum Canal from two reservoirs located in the American River watershed. Water that is released from Lake Valley Reservoir and Kelly Lake (storage capacities of 7,964 af and 336 af, respectively) is diverted at the Lake Valley Diversion Dam into the 36 cfs capacity Lake Valley Canal, eventually discharging into the Drum Canal.

Table 4.3-22 Minimum Releases Associated with the Drum and Alta Powerhouses

Facility	Time Period	Minimum Release (cfs)
Lake Valley Reservoir	10/1-5/31 6/1-9/30	1 3
North Fork of the North Fork American River below Lake Valley canal diversion	10/1-5/31 6/1-9/30	1 3
Drum Forebay	Norm 3/1-9/30 10/1-2/28-29 Dry Year round	 10 5 5
Canyon Creek downstream Drum Forebay	Year Round	1
Canyon Creek Downstream of Towle Canal diversion	Year Round	1 or NF whichever is less
Little Bear R. from Alta PH	Year Round	3 continuous flow

Source: PG&E Co., 1999

Agreements between Pacific Gas and Electric Company, the CDFG, and the USFS require that a continuous release of one to three cfs is made below Lake Valley Diversion Dam (PG&E Co., 1963a).

The Drum Canal, located in the Bear River watershed, extends nine miles to the Drum Forebay. The 621-af forebay supplies water to both the Drum 1 and 2 Powerhouses (103.5 MW) as well as to the Alta Powerhouse (2.0 MW) and to PCWA. Normal maximum gross head at the Drum 1 and Drum 2 Powerhouses is 1,373 and 1,370 feet, respectively. The normal maximum gross head at the Alta Powerhouse is 648 feet (PG&E Co., 1998d). There are three penstocks emerging from Drum Forebay. Penstocks 1 and 2 supply water to Drum 1 Powerhouse. Constructed in 1913, this powerhouse discharges a combined total of 643 cfs into the Drum Afterbay on the Bear River. Penstock 3 supplies water to the Drum 2 Powerhouse, which discharges 505 cfs into the Drum Afterbay.

In addition to supplying the Drum Powerhouses, water from the Drum Forebay is released into Canyon Creek where it is diverted downstream into the Towle Canal. The 45-cfs capacity Towle Canal carries the water 3.9 miles to the Alta Forebay (29 af). Water from the Alta Forebay is used to supply both Pacific Gas and Electric Company's Alta Powerhouse and PCWA's Alta water treatment plant. The maximum capacity of the Alta Powerhouse is 56 cfs. Water discharging from the Alta Powerhouse is either diverted into PCWA's Boardman Canal for irrigation and domestic use or discharged downstream in the Little Bear River.

Agreements between Pacific Gas and Electric Company and CDFG require a continuous three cfs minimum flow in the Little Bear River below Alta Powerhouse. FERC License Article 39 stipulates a minimum flow of one cfs or the natural flow in Canyon Creek (whichever is less) downstream of the Towle Diversion.

Dutch Flat 1 Powerhouse. The Dutch Flat 1 Powerhouse facility originates with water stored in the Drum Afterbay, on the Bear River. Storage in the afterbay includes discharge water from the Drum 1 and 2 Powerhouses and any water spilled from the South Yuba and Drum Canal into the Bear River. Water in the Drum Afterbay is composed of combined Pacific Gas and Electric Company and NID water supplies, and as such, is used to supply two independent hydroelectric generating facilities. A portion of the afterbay water is diverted into Pacific Gas and Electric Company's Dutch Flat 1 tunnel, a four-mile-long tunnel with a 490 cfs capacity leading to Pacific Gas and Electric Company's Dutch Flat 1 Powerhouse (22 MW). Another portion of the water is diverted into NID's six-mile-long 600 cfs capacity Dutch Flat 2 Canal that leads to NID's Dutch Flat 2 Powerhouse which is part of the NID's Yuba-Bear Asset (FERC No. 2266).

Table 4.3-23 Minimum Releases Associated with the Dutch Flat Powerhouse

Facility	Time Period	Minimum Release (cfs)
Bear River downstream Drum afterbay	Norm March-Sept. Oct-Feb. Dry year Year round	 10 5 5
Bear River downstream of Dutch Flat afterbay	5/1-10/31 11/1-4/30	10 5
Bear River downstream of Rollins Reservoir	Norm 5/1-10/31 11/1-4/30 Dry 5/1-10/31 11/1-4/30	 75 20 40 15

Source: PG&E Co., 1999

FERC License Article 39 also requires a variable minimum release from Drum Afterbay into the Bear River of ten cfs (March through September) and five cfs (October through February). Bear River flows and powerhouse discharges collect in the Dutch Flat Afterbay.

NID operates the Dutch Flat Afterbay Dam to divert water into the Chicago Park flume, where it passes through NID's Chicago Park Powerhouse. Water discharged from the Chicago Park Powerhouse flows into NID's Rollins Reservoir, located on the Bear River. This 66,000-af reservoir is used to supply water to NID's Rollins Powerhouse located at the base of Rollins Dam. Water discharging from Rollins Powerhouse is either diverted into Pacific Gas and Electric Company's Bear River Canal or left in Bear River for irrigation and domestic use downstream. The NID powerhouses and reservoirs are dispatched, by contractual obligation, in combination with the operation of the Drum-Spaulding System.

Halsey Powerhouse. The Halsey Powerhouse facility uses water discharged from the Rollins Powerhouse and diverted immediately downstream at the Bear River Diversion Head Dam. Up to 470 cfs of powerhouse tailrace water is diverted into the 24-mile-long Bear River Canal, which empties into Halsey Forebay. Water is delivered to PCWA at various locations along the Bear River Canal. The 244-af Halsey Forebay is used to supply Halsey Powerhouse (11 MW). The powerhouse has a flow capacity of 495 cfs. Water discharging from Halsey Powerhouse flows into Halsey Afterbay. The powerhouse operates at a normal maximum gross head of 328 feet (PG&E Co., 1998d). Halsey Afterbay, also known as Christian Valley Reservoir, has a storage capacity of 106 af and provides for the diversion of the water into the Wise Canal.

There are no minimum flow requirements below either Halsey Forebay or Afterbay. Although the capacity of the Bear River Canal is slightly less than that of Halsey Powerhouse, the powerhouse can run at full load for short periods of time by utilizing the stored water in Halsey Forebay. Typically during the summer periods, reduced flow in the Bear River Canal (430 - 450 cfs) occurs due to restricted flows as a result of algae growing in the canal and irrigation deliveries made upstream from Halsey Forebay.

Wise 1 and 2 Powerhouses. The Wise 1 and 2 Powerhouses are linked directly to the Halsey Powerhouse. Water entering the Wise Canal from Halsey Afterbay travels for approximately six miles before entering Wise Forebay. The Wise Canal has a capacity of 490 cfs. There are numerous delivery points located along the Wise Canal that provide irrigation and domestic supply to both NID and PCWA. In between Halsey Afterbay and Wise Forebay lies Rock Creek Reservoir. This 548-af reservoir provides for an intermediate regulating point for the Wise Canal. Rock Creek Reservoir can be used to store water from the Wise Canal for short periods during system disruptions without having to interrupt flow in the entire canal system. Water is also diverted from Rock Creek Reservoir into PCWA's Middle Fiddler Green Canal, which is used for irrigation and domestic deliveries to NID and PCWA. The Wise Canal flows out of Rock Creek Reservoir into the Wise Forebay. The Wise Forebay, with a storage capacity of 32 af, provides an additional delivery point to PCWA's Lower Fiddler Green Canal before the water flows through Wise Powerhouse. Wise 1 Powerhouse, constructed in 1917, consists of a single unit. In 1986, a second powerhouse, Wise 2, was added. Wise 1 and Wise 2 Powerhouses (17.1 MW) have flow capacities of 383 and 80 cfs, respectively. The Wise 1 and 2 Powerhouses both operate at a normal maximum gross head of 519 feet. (PG&E Co., 1998d).

The Wise Canal has a higher flow capacity than the combined flow capacities of the powerhouses because it is needed to meet irrigation deliveries along the canal prior to reaching the powerhouses. During irrigation season (April 15 - October 15), the powerhouses are operated at reduced capacity. The powerhouses are fed from a single penstock exiting from Wise Forebay which then bifurcates before entering the two plants.

Newcastle Powerhouse. The water that is discharged from both Wise 1 and Wise 2 Powerhouses can either be diverted directly from the tailrace into the South Canal or spilled to the Auburn Ravine (a natural watercourse) for irrigation delivery to NID or PCWA. The South Canal travels for 6.7 miles before emptying into Newcastle header box. There are numerous delivery points located along the South Canal that provide irrigation and domestic water to PCWA. The South Canal has a capacity of 450 cfs. The Newcastle header box has a capacity of 15 af and allows the water to enter the Newcastle penstock and powerhouse. In addition, there is a PCWA delivery point located at the Newcastle header box. Any water spilling from Newcastle header box will enter Folsom Lake. FERC License Article 63 requires a minimum flow release below Newcastle header box of five cfs year round. Newcastle Powerhouse (11.5 MW), constructed in 1986, has a flow capacity of 392 cfs. The South Canal has a higher flow capacity than Newcastle Powerhouse owing to the fact that some of the water is diverted to the irrigation delivery points before reaching the powerhouse. Water discharged from Newcastle Powerhouse flows directly into Folsom Lake on the American River. Folsom Lake is part of the Federal Water Project and is operated by the U.S. Bureau of Reclamation (USBR).

Table 4.3-24 Minimum Releases Associated with the Newcastle Powerhouse

Facility	Time Period	Minimum Release (cfs)
Below Newcastle header box	Year round	5

Source: PG&E Co., 1999

Water Delivery and Domestic Use. While the operation of the Drum-Spaulding System is based on the primary purpose of power generation, its operation is also influenced by contracts and agreements between Pacific Gas and Electric Company and other water users in the drainage basin. NID owns and operates the Yuba-Bear Assets, which use water in the Middle and South Fork Yuba River, North Fork American River, Deer Creek, and the Bear River. The cooperation of the Pacific Gas and Electric Company and NID facilities within these drainage basins is determined by the 1963 Consolidated Contract (PG&E CO., 1963b). The operation of the Drum-Spaulding System is also affected by the 1978 Rollins Power Purchase Contract with NID, which determines costs paid by Pacific Gas and Electric Company for NID-owned water (PG&E Co., 1978b).

In addition to the system described above, the NID Yuba-Bear Assets also represent an extensive system of reservoirs, powerhouses, and canals that are commingled with the Drum-Spaulding System through a combination of physical structures and complex water rights and operational agreements. The three NID powerhouses, Dutch Flat 2, Chicago Park, and Rollins, are dispatched under the power purchase agreements by Pacific Gas and Electric Company. NID delivers water to the upper portion of the Drum-Spaulding System, then uses this water at various delivery points along the downstream end of the system. Water from the Drum-Spaulding System and from the Yuba-Bear Assets are blended together, flowing through both Pacific Gas and Electric Company and NID powerhouses prior to reaching these downstream delivery points.

Separate water contracts with the PCWA also allow for the sale of irrigation and domestic water in the downstream end of the system from numerous delivery points (PG&E Co., 1963c). In essence, powerhouses at the lower end of the Drum-Spaulding System are operated to meet the irrigation demand of these two agencies (NID and PCWA). This means that the powerhouses are primarily block-loaded or operated for a fixed demand of water. Block-loading occurs when the powerhouse is operated at a fixed output for long periods of time, versus peak loading when the powerhouse output varies according to grid system demand over short periods of time, usually hourly. Peaking operations do exist at the upstream end of the system, primarily at Drum 1 & 2, and Dutch Flat Powerhouses.

As discussed above and described in Chapter 2, Pacific Gas and Electric Company has water rights in the Drum-Spaulding System. There are additional contracts for water delivery or supply.

Water Quality. The beneficial uses associated with the Yuba and Bear Rivers are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Yuba River from Englebright Dam to the Feather River are:

- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat (COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

Listed uses for the Bear River are the same, with the addition of municipal supply (MUN). Migration and spawning are listed as potential, as opposed to existing, uses on the Bear River.

FERC License Article 41 requires Pacific Gas and Electric Company to take precautions to prevent clay, silt, gravel, fines, detritus, oil, or other substances from entering streams or waters below the facilities (FPC, 1963). FERC License Article 19 requires Pacific Gas and Electric Company to take reasonable measures to prevent stream sedimentation and any other form of water pollution.

Placer County Water Agency (PCWA) and Nevada Irrigation District (NID) routinely perform water quality testing for the Yuba and Bear Rivers at water treatment plants, eight of which receive water conveyed through the Pacific Gas and Electric Company system (primarily the Boardman Canal). Table 4.3-25 lists ranges of concentrations for several water quality parameters tested at several locations in this bundle. Lowest average monthly raw water turbidity for a four-year period from 1991 to 1994 ranged from 0.02 to 0.05 NTU. Average highs ranged from 0.23 to 0.39 NTU.

The Bear River and Yuba River (North, Middle, South) are not included on either the CWA 303(d) TMDL list or the Water Quality Limited Segments list (RWQCB, 1998; USEPA, 1999). There is no current CWA 401 certification for older facilities that pre-date the Clean Water Act. The Central Valley RWQCB took no action on requests for certification for the five newer powerhouses, thus these facilities are deemed waived.

Water temperature has been an issue in the Bear River, which receives flows from the system (Lake Spaulding via South Yuba or Drum canals) prior to re-diversion of flows into the Upper Boardman Canal. The FERC-ordered abandonment of the Upper Boardman Canal (FERC, 1994b) was a concern due to the potential warming of the Bear River without the additional flow augmentation from the South Yuba or Drum canals. Water temperature studies indicated that temperatures were suitably low for trout survival and growth even without the inflow from the canals. The State does not necessarily agree with this finding noting that the Basin Plan criteria is protection of all beneficial uses (SWRCB, 2000). In relicensing the State will have the responsibility to ensure protection of beneficial uses.

Algacides have been applied to some of the canals in the Drum-Spaulding area. Algacide applications require State and Federal EPA registration, supervision by a Licensed Pest Control Operator, annual registration with the County Agricultural Commissioner, and monthly pesticide use reporting to each commissioner.

Water quality is a potential issue for Pacific Gas and Electric Company’s Blue Lake and White Rock camping areas, due to a lack of restroom facilities. Although signs have been posted about removal of personal waste, there is no ongoing monitoring to determine if water quality is being degraded.

Table 4.3-25 Ranges of Water Quality Parameters for the Yuba and Bear Rivers

Parameter	Sampling Location					
	Alta WTP	Monte Vista WTP	Colfax WTP	Auburn/ Bowman WTP	Foothill/ Sunset WTP	Newcastle
Turbidity (NTU)	0.03 – 0.39	0.03 – 0.38	0.03 – 0.23	0.02 – 0.23	0.02 – 0.23	0.05 – 0.23
Total Dissolved Solids (mg/l)	23.0 – 33.0	35.0 – 71.0	33.0 – 51.0	22.0 – 56.0	24.0 – 45.0	26.0 – 50.0
pH	6.5 – 8.9	6.6 – 8.9	6.3 – 8.7	6.8 – 8.9	6.8 – 8.8	6.1 – 8.9
Hardness (as CaCO3) (mg/l)	7.0 – 11.0	8.0 – 37.0	17.0 – 25.0	17.0 – 46.0	14.0 – 27.0	15.0 – 31.0
Cl (mg/l)	2.9 – 11.0	7.8 – 14.0	4.0 – 11.0	2.0 – 8.2	3.0 – 7.6	7.0 – 13.0
Fe (mg/l)	<0.030 – 0.061	<0.03 – 0.3	<0.03 - <0.03	<0.03 - <0.03	<0.03 - <0.03	<0.03 – 0.04
Cu (mg/l)	<0.02 - <0.02	<0.02 - <0.02	<0.02 - <0.02	<0.02 - <0.02	<0.02 - <0.02	<0.02 - <0.02
NO3 (mg/l)	<1.0 – 1.6	<0.5 – 2.0	<0.5 - <1.0	<0.5 – 1.6	<0.5 - <1.0	<0.5 – 1.7
Fecal Coliform (MPN/100ml)	<2.0 – 1,600	11.0 – 1,600	3.0 - >1,600	22 – 16,000	<2.0 - >1,600	<1.0

*Samples are taken from above water treatment plant intakes.
*Single numbers express averages instead of minimum-maximum ranges.
Source: NID/PCWA, 1996.

Potential sources of surface water quality concerns identified in the upper Yuba-Bear watershed include livestock grazing, timber harvesting, recreation, wildlife, and residential septic system use. Hydroelectric facilities were not identified as a contributor to surface water quality conditions, and no recommendations specific to operation of Pacific Gas and Electric Company facilities' operation with respect to water quality have been identified (NID/PCWA, 1996).

NID and PCWA concluded that the management practices, monitoring levels, and treatment processes were adequate to meet the requirements of the Surface Water Treatment Regulation. The 1996 *Final Draft Sanitary Survey for the Yuba and Bear River Watersheds* (NID/PCWA, 1996) identified recommendations to maintain water quality conditions. These included: ongoing review of activities in the watershed that could affect water quality, and developing and implement a plan of increased monitoring and investigation of raw water supply to the plant in order to locate and mitigate sources of contamination. The survey also recommended increased testing for giardia and cryptosporidium.

Groundwater. No information was collected about the groundwater within the Drum-Spaulding Bundle as the facilities do not use groundwater.

Bundle 12: Chili Bar

The Chili Bar Bundle consists of FERC No. 2155 (the Chili Bar Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

Chili Bar (FERC 2155)

The Drainage Basin and Water Sources. The Chili Bar System is located on the South Fork American River (SFAR), in El Dorado County. The headwaters of the SFAR originate near Echo Summit at an elevation of approximately 7,500. The drainage area within the SFAR watershed that is used by the Chili Bar System is 598 square miles, as measured directly below the dam (USGS, 1997).

Hydroelectric Facilities. The asset consists of the Chili Bar Hydroelectric Generating Facility. The facility has a single powerhouse, reservoir and diversion, and associated appurtenant facilities (for example, penstocks and conduits), as shown in Figure 4.3-10.

Water Management. The major storage and water use in the river system is controlled by SMUD, with a usable storage capacity of 385,060 af at several storage facilities upstream of the Chili Bar facilities. Water discharged from SMUD's White Rock Powerhouse to the SFAR is impounded at Chili Bar Dam. The Chili Bar Powerhouse (7.0 MW) uses water stored in Chili Bar Reservoir, with a usable storage capacity of 3,139 af. A penstock, located at the dam, conveys water from the reservoir to the powerhouse. Water is discharged through the penstock at a normal maximum flow of 1,659 cfs. Tailrace water enters directly into the SFAR. Maximum normal gross head at the facility is 60 feet (PG&E Co., 1998d). The Chili Bar System operates in a baseload mode.

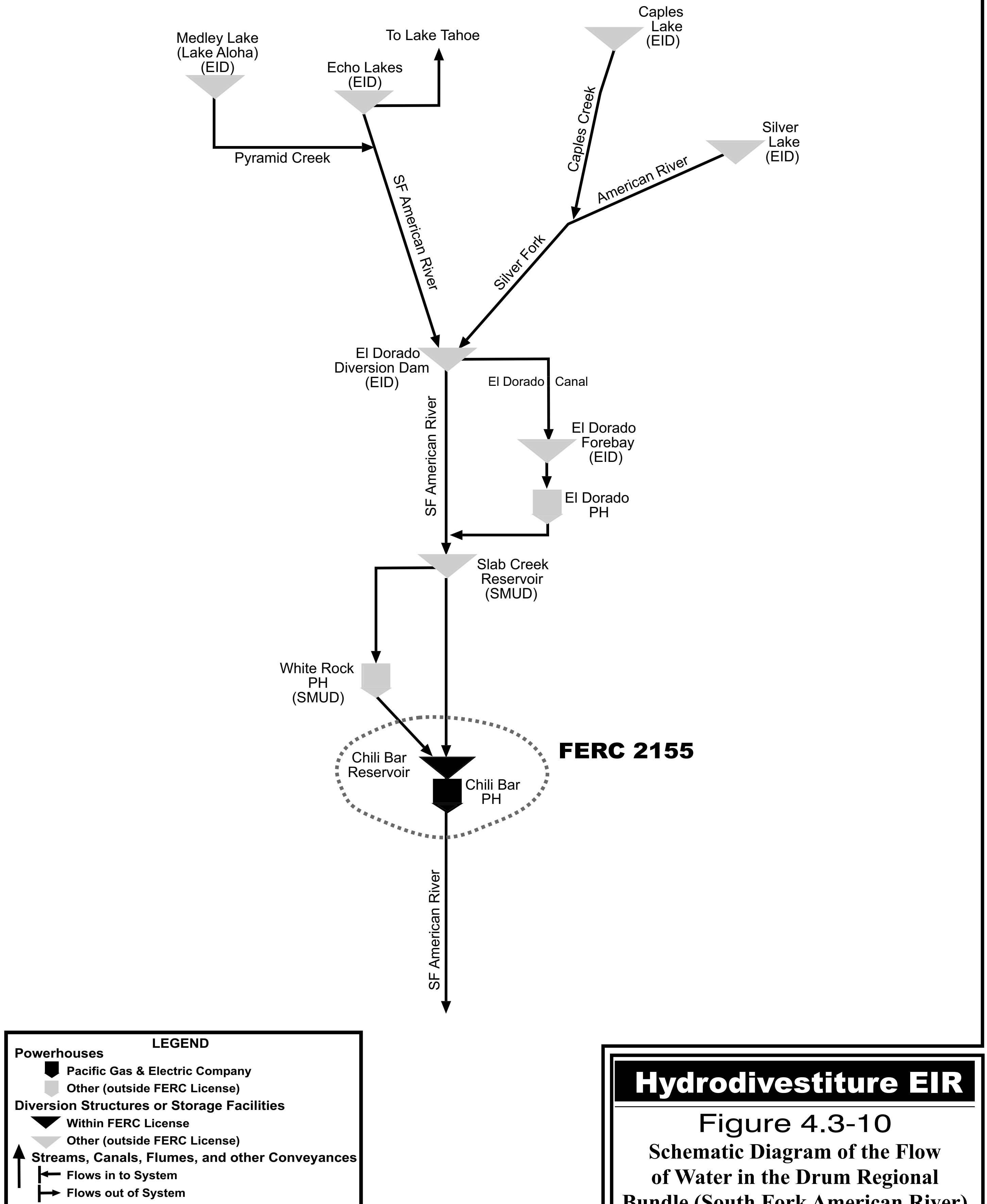
As part of the FERC license requirements, minimum flows must be maintained downstream of the ChiliBar Powerhouse. The FERC requirements are defined in Table 4.3-26 and discussed below.

Table 4.3-26 Minimum Releases Associated with Chili Bar System

Facility	Time Period	Minimum Release (cfs)
South Fork American River downstream Chili Bar PH	Year Round	100[a]

[a] Article 27 amending ramping rate requirements states controllable discharge changes shall be gradual and no greater than 550 cfs per hour from 100 to 1,000 cfs, and not to exceed one foot in elevation during any one hour period above 1,000 cfs, except during natural spill conditions.

Water releases from the reservoir and the powerhouse determine downstream flows in the SFAR. FERC License Article 27 requires a minimum flow of 100 cfs below the dam, and places a flow ramping rate restriction on the facility (FERC 1992c). The change in controllable discharge can be



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-10

Schematic Diagram of the Flow of Water in the Drum Regional Bundle (South Fork American River)

Aspen Environmental Group

no more than would increase or decrease the stage of the river by one foot in elevation during any one hour period. The mean average annual flow in the river downstream of the powerhouse between 1965-1996 was 1,426 cfs.

In the past, Pacific Gas and Electric Company and SMUD have coordinated operations of the Chili Bar and White Rock Powerhouses in an effort to accommodate both operational water flow and summertime whitewater recreation downstream of the powerhouses. There is currently no formal agreement to do so.

Water Quality. The beneficial uses associated with the South Fork American River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the SFAR from Placerville to Folsom Lake are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat (COLD)
- Wildlife Habitat (WILD)

According to the *1998 El Dorado County River Management Plan Update*, there are two major issues related to water quality that may affect the waters at the Chili Bar facilities – impacts caused by sewage-related problems, and erosion of the riverbanks.

Recreational use of the South Fork American River has increased over the last few decades, which includes whitewater boating, rafting, swimming, fishing, picnicking, camping, and dredge mining. There are 18 private and public facilities with 153 toilets along the riverbank. Most of the public and private toilet facilities use septic tank/leach field systems for treatment and disposal of the sewage. The mountains and hills outside the river floodplain and the materials underlying the river deposits are cemented and crystalline bedrock, which is non-water bearing and not suitable for leach field disposal of sewage. Under these conditions, it is supposed that leach field facilities near the river have been constructed in riverbank floodplains. Leach fields constructed in good-quality soils provide sufficient treatment to remove coliform, nitrates, and other pathogens. If the leach field is in open gravel or fractured bedrock, however, it may not provide the same level of treatment before the sewage enters the river.

According to the 1998 report, it appears that contamination of the South Fork American River occurs primarily from animal waste and perhaps some defective septic tank leach field sewage disposal systems, and other undocumented sources. These outweigh the contamination originating from rafting activities. Elevated winter and early spring readings preclude rafting as the main source of contamination because rafters are not present in great numbers during these winter and spring periods. All of the riverbank counts for coliform tend to indicate that there is an upstream source of unknown higher count. The elevated winter and early spring numbers indicate probable inundation of leach fields by high water table conditions as a result of winter and spring runoff, and are discharging untreated sewage directly to the surface without filtration.

In addition to the sewage effects, there is an adverse effect on native vegetation with increases in erosion where access paths are made. Erosion and waste also result from near river camping and picnicking before, during, and after the whitewater trip. Additionally, the increase in domestic pets on these rafting trips also increases erosion. Water samples taken in December 1997 indicated that there was an increase in turbidity in the South Fork American River during the first period of high river flows. Sources were probably soils being washed into the river from disturbed areas, landslides, or erosion of the riverbank.

A new water monitoring program was initiated in August of 1997. This program monitors fecal coliform, nitrate, pH, electrical conductivity, turbidity, and temperature at several points throughout the system. The program continues to analyze impacts to water quality and sources of contamination (El Dorado County, 1998).

Groundwater. No information was collected about the groundwater within the Chili Bar bundle as the facility does not use groundwater.

4.3.4.4 Motherlode Regional Bundle

The Motherlode Region includes four FERC licenses covering eight powerhouses with a combined capacity of 318 MW. There are three separate bundles located in the Motherlode Region: Mokelumne River, Stanislaus River, and Merced River (see Figure 2-27 in Chapter 2). The following sections describe water resources for each of Pacific Gas and Electric Company's FERC-licensed facilities in the Motherlode Region. Specifically, these sections describe each drainage basin and the location of the facilities, describe how water is used at each facility, describe the flow of water through the different facilities, and describe water diversion and use by other beneficial users. These sections also provide a description of water conveyance systems and capacities, as well as maximum powerhouse capacity.

When applicable, the unique water use constraints, such as physical capacity constraints, storage constraints, and regulatory restrictions (e.g., instream flow release requirements) included in FERC licenses, are discussed for each facility. Schematic diagrams depict the flow of water.

Regional Setting

The Motherlode Region is located in Amador, Tuolumne, and Merced counties in the Sierra Nevada. Lying southwest of Lake Tahoe and northwest of Mono Lake, the area contains 27 dams located on three rivers. Located in the middle of the Sierra Nevada mountains, the rivers drain the area west of Mt. Reba-Bear Valley. Total capacity of the system is 312 MW. The site of California's Gold Rush, some canals date back to the late 1800s. The general layout of the Motherlode facilities and the major hydrographic features within this regional bundle are shown in Figures 2-25 and 2-26 in Chapter 2.

The North Fork Mokelumne River has a drainage area of 365 square miles at the Electra Powerhouse. There are five powerhouses in the North Fork Mokelumne River—Salt Spring #1, Salt Springs #2, Tiger Creek, West Point, and Electra. The principal storage reservoirs in this bundle are the Lower Bear River reservoir and Salt Springs reservoir. The watershed is located in Amador and Calaveras counties. Mean annual precipitation in the Mokelumne River watershed ranges from 20 inches at Electra powerhouse to 75 inches at the Sierra Nevada crest. Most runoff occurs in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season.

The South Fork Stanislaus River watershed (FERC 2130) has a watershed area of 45 square miles at Strawberry Reservoir (Pinecrest Lake). This watershed is located in Stanislaus County. Mean annual precipitation ranges from 40 inches at Pinecrest Lake to 65 inches at the Sierra Nevada crest. Most runoff occurs in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season. Releases from Pinecrest (Strawberry) Lake serve the Stanislaus and Spring Gap powerhouses. Releases from Relief Reservoir on the upper Middle Fork Stanislaus River supplement flows through Tri-Dam's Donnells, Beardsley, and Sand Bar facilities, and the Stanislaus Powerhouse.

The South Fork Stanislaus River watershed (FERC 1061) has a watershed area of 67 square miles at Lyons Reservoir and is located downstream of Pinecrest Lake. This watershed is located in Stanislaus County. Mean annual precipitation ranges from 30 inches at Lyons Reservoir to 65 inches at the Sierra Nevada crest. Most runoff occurs in April-June, with a maximum usually in May, from snowmelt. In some years, significant flows occur in the November-February period from rain and rain on snow. Very low base flows occur in the August-October summer-fall dry season. Releases from the only storage, Lyons Reservoir, serve the Phoenix Powerhouse.

The Merced River watershed (FERC 2467) has a drainage area of 1061 square miles at Merced Falls Powerhouse. The watershed is located in Mariposa County. Mean annual precipitation ranges from 20 inches at Merced Falls Powerhouse to 65 inches at the Sierra Nevada crest. The Merced Falls Powerhouse is a run-of-the-river facility.

To produce more power, Pacific Gas and Electric Company enhances natural precipitation by conducting cloud seeding in the Mokelumne River watershed above Salt Springs Reservoir. Table 4.3-27 provides the location of the cloud seeding stations in the Motherlode Watershed Region.

Table 4.3-27 Cloud Seeding Stations for the Motherlode Regional Bundle

Name of Facility	Property Owner	Location	General Location
Stanislaus Meadow	USFS – Stanislaus	NE1/4, Sec. 36, T8N, R18E	Near Markleeville
Mt. Reba	USFS – Stanislaus	SE1/4, Sec. 5, T7N, R18E	Near Markleeville
Mattley Meadow	USFS – Stanislaus	NW1/4, Sec. 20, T7N, R17E	Near Long Barn
Cole Creek	Unknown	SE1/4, Sec. 14, T8N, R16E	Near Pioneer
Upper Bear River	Boy Scouts	SE1/2 of SE1/4, Sec. 36, T9N, R16E	Near Pioneer
Sapps Hill	USFS – Stanislaus	SE1/4, Sec. 31, T7N, R18E	Near Long Barn

Source: PG&E Co., 1999

Local Regulations and Policies

Refer to Section 4.3.2.

Bundle 13: Mokelumne River

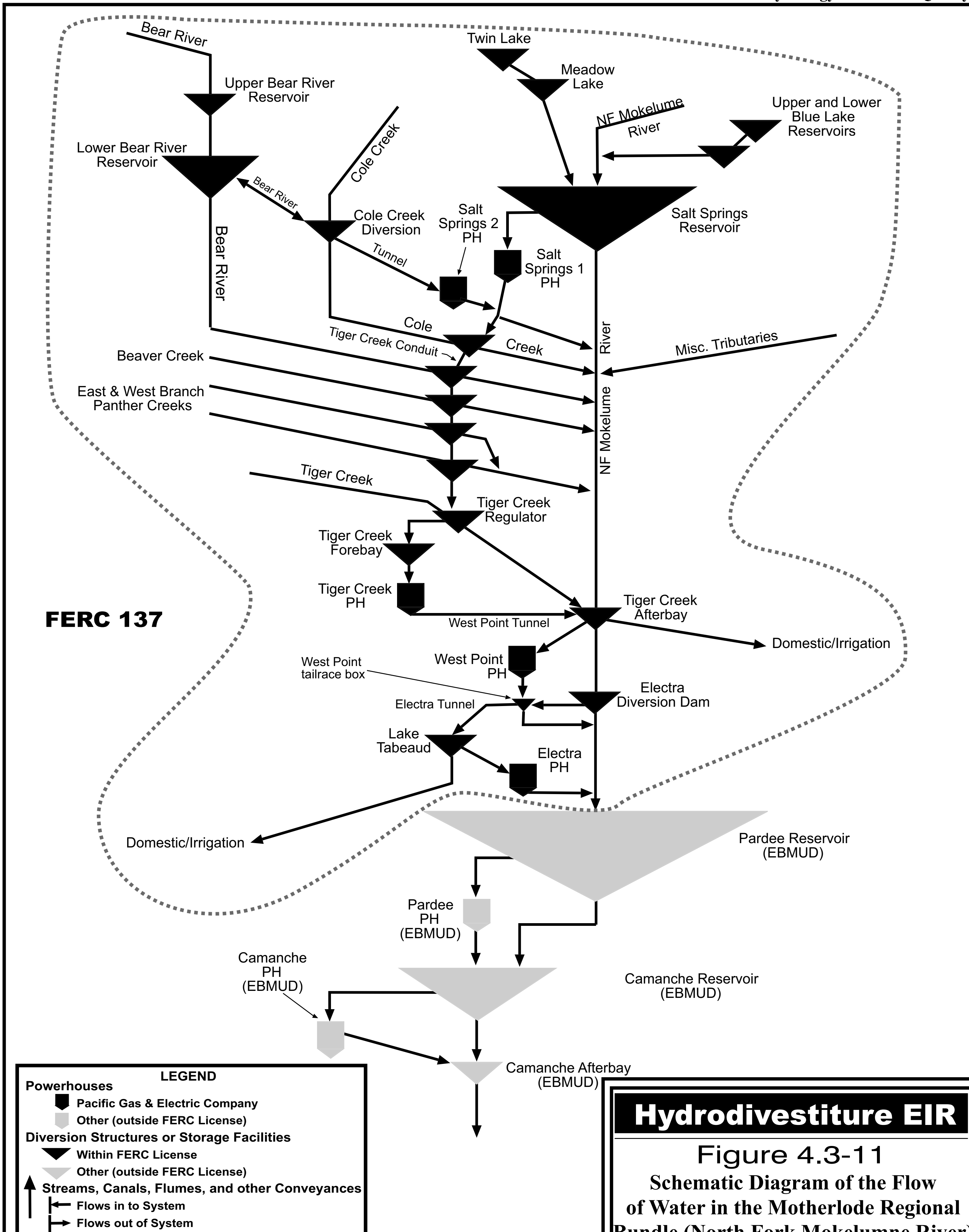
The Mokelumne River Bundle consists of FERC No. 0137 (the Salt Springs, Tiger Creek, West Point, and Electra Hydroelectric Generating Facilities and associated appurtenances). These assets are being bundled together to maintain FERC license No. 0137.

Mokelumne River (FERC 0137)

The Drainage Basin and Water Sources. The Mokelumne River System, which includes the Tiger Creek Service Center, lies within the North Fork Mokelumne River (NFMR) drainage basin, in Alpine, Amador, and Calaveras Counties. The Mokelumne River originates on the west slope of the central Sierra Nevada. The Mokelumne River's main artery is the NFMR, with headwaters along the Sierra Nevada crest near Carson Pass at elevation 7,830 feet. Many of the system's storage and diversion reservoirs are located on tributaries that flow south to the NFMR. The drainage area within the NFMR basin that is utilized by the system is 365 square miles, as determined directly below the most downstream diversion facility, Electra Diversion Dam (USGS, 1997).

Hydroelectric Facilities. The asset consists of four distinct hydroelectric generating facilities: Salt Springs, Tiger Creek, West Point, and Electra. Each facility is comprised of a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-11.

Water Management. Water use and management for the system originate in a series of high-elevation reservoirs of the Salt Springs facility. Four lakes (Upper Blue, Lower Blue, Twin, and



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-11

Schematic Diagram of the Flow of Water in the Motherlode Regional Bundle (North Fork Mokelumne River)

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Meadow) at an approximate elevation of 8,000 feet, provide a combined gross storage capacity of 19,254 af (PG&E Co., 1998d). Water released from these four lakes transits the NFMR for approximately 20 miles to the 141,857-af Salt Springs Reservoir, where it is stored prior to release into the penstock for Unit 1 of the Salt Springs Powerhouse (44 MW). Upper and Lower Bear River reservoirs (elevation 5,800 feet), which provide another 59,331 af of usable storage capacity for the development (PG&E Co., 1998d), lie on the Bear River, a tributary to the NFMR (and a different stream than the Bear River of the Drum-Spaulding bundle). Water stored in these reservoirs is released directly into the Bear River Tunnel with a capacity of 800 cfs. It then enters the Bear River Penstock with a capacity of 225 cfs and eventually through Unit 2 of the Salt Springs Powerhouse. Flow in the tunnel is augmented by water diverted from nearby Cole Creek. Normal maximum flow through the two units at Salt Springs Powerhouse is 818 cfs (PG&E Co., 1998d). Unit 1 of the Salt Springs Powerhouse has a normal maximum gross head of 257 feet while Unit 2 has 2,117 feet (PG&E Co., 1998d). Salt Springs is operated as a baseload facility, and was identified by the California ISO as a Reliability Must Run facility for 1999.

FERC License Articles 30 (FPC 1925) and 36(FERC, 1982) specify a number of minimum flow releases from the different facilities associated with the Salt Springs Development. These are shown in Tables 4.3-28 through 4.3-32.

Table 4.3-28 FERC License Minimum Releases Associated with the Salt Springs Generating Facility

Facility	Time Period	
	May 1 - October 31	November 1 - April 30
Cole Creek Diversion	2 cfs or natural flow	2 cfs or natural flow
Upper Blue Lake	2 cfs	2 cfs or natural flow
Lower Blue Lake	2 cfs	2 cfs or natural flow
Meadow Lake	2 cfs	2 cfs or natural flow
Lower Bear River Reservoir	4 cfs normal year 2 cfs dry year	2 cfs
Salt Springs Reservoir	10 cfs normal year 5 cfs dry year	5 cfs

Source: PG&E Co., 1999

The Mokelumne River System is currently undergoing relicensing, and the new license is expected to contain revised minimum release requirements. Pacific Gas and Electric Company and CDFG currently have an agreement that stipulates minimum release flows at several locations in the Mokelumne River System area (PG&E Co., 1996d). These are shown for the Salt Springs and Tiger Creek facilities in Tables 4.3-29 and 4.3-30.

Table 4.3-29 CDFG Minimum Releases Associated with the Salt Springs Generating Facility

Facility	Time Period	
	May 1-October 31	November 1-April 30
Cole Creek Diversion	2 cfs or natural flow	2 cfs or natural flow
Upper Blue Lake	2 cfs	2 cfs or natural flow
Lower Blue Lake	15 cfs normal year 7.5 cfs dry year	2 cfs or natural flow
Twin Lake	1 cfs	1 cfs
Meadow Lake	5 cfs	2 cfs or natural flow
Lower Bear River Reservoir	4 cfs normal year 2 cfs dry year	2 cfs
Salt Springs Reservoir	30 cfs normal year 20 cfs dry year	20 cfs

Source: PG&E Co., 1999

In addition to minimum flow releases, Pacific Gas and Electric Company maintains an agreement with CDFG stipulating minimum storages for various reservoirs as depicted on the following table.

Table 4.3-30 CDFG Minimum Storages Associated with the Salt Springs and Tiger Creek Generating Facilities

Facility	Storage
Twin Lake	1207 acre feet/ draft for fish water release only
Upper Bear River Reservoir	500 acre feet
Lower Bear River Reservoir	3,300 acre feet
Salt Springs Reservoir	4,993 acre feet
Tiger Creek Regulator	100 acre feet

Source: PG&E Co., 1999

Tailrace water from the Salt Springs Powerhouse immediately enters the upper section of the Tiger Creek Canal (capacity 550 cfs). Tailrace flows in excess of the capacity of the canal (up to about 268 cfs under normal maximum operating conditions) are released into the NFMR. These releases, in combination with minimum releases made at Salt Springs Reservoir Dam, constitute flows in the NFMR downstream of the dam, which have averaged 222 cfs between 1927 and 1996 (USGS, 1997).

The Tiger Creek Canal transports water 17.8 miles to the 522-af Tiger Creek Regulator Reservoir. As the water transits the canal, it is augmented by diversions at five streams: Cole Creek, Bear River, Beaver Creek, East Panther Creek, and West Panther Creek.

In accordance with the FERC license, Pacific Gas and Electric Company releases water into each diverted stream. Minimum water release requirements range from 0.5 cfs to ten cfs, depending on the facility, time of year, and water year type, as summarized below.

Table 4.3-31 CDFG Minimum Releases Associated with the Tiger Creek Generating Facility

Facility	Time Period	
	May 1-October 31	November 1-April 30
NF Mokelumne blw. Bear River	40 cfs normal year 20 cfs dry year	20 cfs
Tiger River Regulator	10 cfs normal year 5 cfs dry year	5 cfs
East Panther Creek Diversion	3.0 cfs or natural flow normal year 1.5 cfs or natural flow dry year	1.5 cfs or natural flow
West Panther Creek Diversion	1.5 cfs or natural flow	1.5 cfs or natural flow
Beaver Creek Diversion	0.5 cfs or natural flow	0.5 cfs or natural flow
Cole Creek Feeder	2.0 cfs or natural flow	2.0 cfs or natural flow

Source: PG&E Co., 1999

Table 4.3-32 FERC License Minimum Releases Associated with the Tiger Creek Generating Facility

Facility	Time Period	
	May 1-October 31	November 1-April 30
Bear River Diversion	4 cfs	4 cfs

Source: PG&E Co., 1999

Water in the Tiger Creek Regulator Reservoir is released to the Tiger Creek Regulator Canal (capacity 625 cfs) and conveyed in an open canal 2.5 miles to the 42 af Tiger Creek Forebay. The water that reaches the Tiger Creek Forebay is released into a penstock leading to Tiger Creek Powerhouse (58.0 MW), located at the confluence of Tiger Creek with the NFMR (elevation 2,340 feet). The maximum capacity of the Tiger Creek Powerhouse is 750 cfs, and the normal maximum gross head is 1,219 feet (PG&E Co., 1998E).

Tiger Creek Powerhouse is typically operated as a peaking unit, responding to system energy needs as determined by the energy market. Tiger Creek was also identified by the California ISO as a Reliability Must Run facility for 1999, but was removed from the 2000 list by the Cal-ISO.

Water exiting the Tiger Creek Powerhouse flows into the 2,607-af Tiger Creek Afterbay, a small reservoir located on the NFMR. Water is released from the afterbay into the NFMR or is diverted into the West Point Tunnel (675 cfs capacity), where it travels 2.8 miles to the West Point penstock, then through the West Point Powerhouse (elevation 2,046 feet). Maximum gross head at the facility is 312 feet (PG&E Co., 1998E).

Pacific Gas and Electric Company also makes minimum flow releases from the Tiger Creek Afterbay into the NFMR. Minimum flow releases range from ten to 18 cfs, depending upon time of year in a normal water year. In a dry year, minimum releases are ten cfs year round.

West Point Powerhouse (14.5 MW) is operated as a baseload facility, and was identified by the California ISO as a Reliability Must Run facility for 1999, though it was removed from the 2000 list by the Cal-ISO.

Tailrace water from the West Point Powerhouse is added to water diverted from the NFMR at the Electra Diversion Dam. The maximum 200 cfs of water diverted is then directed into the 8.2-mile-long Electra Tunnel (875 cfs capacity) which transports it to the 1,259-af Lake Tabeaud.

Table 4.3-33 FERC License Minimum Releases Associated with the Electra Generating Facility

Facility	Time Period	Minimum Release (cfs)
Electra Diversion dam	Feb-Apr May-June	200 (Lodi Decree) [1] 300(Lodi Decree) [1]
NFMR below West Point Powerhouse	5/1-10/31 11/1-4/30	15 FERC and CDFG(normal year) 10 FERC and CDFG (dry year) 10 FERC and CDFG (all years)

[1]For a descrption of the Lodi Decree see below.

Source: PG&E Co., 1999

During normal years, minimum releases from the Electra Diversion Dam are 15 cfs May 1 through October 31 and ten cfs the remainder of the year. During dry years, minimum releases are ten cfs year round. From Lake Tabeaud, a maximum of 15,000 af/year water is released into the Amador County Water Agency (ACWA) Canal for irrigation and domestic use. Maximum summertime flow in the ACWA Canal is 30 cfs and minimum flow is eight cfs. The remaining water at Lake Tabeaud is released into a tunnel to the Electra Powerhouse (92.0 MW) through a 1,130 cfs capacity penstock. Maximum normal gross head at the powerhouse is 1,272 feet (PG&E Co., 1998E). Typical non-spring operations run about 875 cfs of water through the powerhouse. Electra Powerhouse, located on the mainstem Mokelumne River at elevation 607 feet, is typically operated as a peaking unit, responding to system energy needs as determined by the energy market. Electra was also identified by the California ISO as a Reliability Must Run facility for 1999, but was removed from the 2000 list by the Cal-ISO.

Mokelumne River flows at the Electra Diversion Dam have been established by two judgments, the Calaveras and the San Joaquin, collectively known as the Lodi Decree. The Lodi Decree requires that in all years, the flows measured at the Electra Diversion Dam must be a minimum of 200 cfs during February through April, and 300 cfs during May and June. When the aggregate storage upstream at the Lower Bear and Salt Springs reservoirs exceeds 130,000 af on June 1, or the precipitation at Salt Springs Powerhouse is equal to or greater than 30” at the end of May, the flow measured at Electra Diversion must be 500 cfs from June 1 through December 31, and 300 cfs the following January. If aggregate storage at the reservoirs is less than 130,000 af as of June 1, but reaches 130,000 af before July 1, then the above flows must also be released. If the aggregate storage does not reach 130,000 af, or the precipitation is less than 30 inches by the end of May, the flow measured at Electra Diversion must be 300 cfs from June 1 through September 30, and 200 cfs from October 1 through January 31, with additional minimum end-of-month storage limits.

Water Delivery and Domestic Use. As described in Chapter 2, Pacific Gas and Electric Company has water rights in the Mokelumne River System. There are additional contracts for water delivery or supply in the system.

Water Quality. The beneficial uses associated with the Mokelumne River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the upper Mokelumne River to Pardee Reservoir are:

- Municipal and Domestic Supply (MUN)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat (COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

The water draining from the Upper Mokelumne River watershed is generally of high quality and is characterized by low turbidity. The North Fork Mokelumne River supports a cold-water fishery, and Pacific Gas and Electric Company states that the current operation ensures the maintenance of cool water temperatures to support this beneficial use. Water temperature in the river is primarily affected by tributary inflow, meteorological conditions, and minimum flows released at the Tiger Creek Afterbay and Electra Diversion. The Company believes that facility releases ensure there is sufficient and cold enough water for trout habitat during warm and dry summer and fall months. The State disagrees with this statement noting that there are documented temperature issues on the North Fork Mokelumne River resulting for low instream flow releases (SWRCB, 2000).

California Department of Fish and Game (CDFG) and Pacific Gas and Electric Company have a 1996 Memorandum of Agreement regarding the routine maintenance for proposed stream or lake alterations (CDFG, 1996). This agreement stipulates that Pacific Gas and Electric Company will maintain the drainage path through the low-level outlet of Tiger Creek Afterbay Dam and can open the outlet when spills are greater than 2,000 cfs. When sluicing occurs, Pacific Gas and Electric Company must monitor the DO and turbidity directly below the dam. This agreement is non-transferable and is in effect through the year 2001. The median turbidity concentration in raw water samples collected by water agencies from two locations downstream of Salt Springs and Lower Bear reservoirs is 0.5 NTU to 4.0 NTU at Tiger Creek Afterbay and below Electra Powerhouse is 0.5 NTU to 12.0 NTU.

Algacides have been applied to the Tiger Creek Canal in the Mokelumne River System area. Algacide applications require State and Federal EPA registration, supervision by a licensed Pest Control Operator, annual registration with the County Agricultural Commissioner, and monthly pesticide use reporting to each commissioner.

Water samples collected in the river by Pacific Gas and Electric Company and Amador County have shown that water quality meets or exceeds State and Federal drinking water standards for heavy metals, total dissolved oxygen (DO), pH, and sulfates. The Lower Mokelumne River (Comanche Reservoir to Delta) is included on the 1998 California CWA 303(d) TMDL list for copper and zinc associated with abandoned mines, and on the Basin Plan Water Quality Limited Segments list, but the upper watershed where Project Lands are located are not included on either list (CVRWQCB, 1998; USEPA, 1998). Some trace metal concentrations have exceeded USEPA action levels in Pardee Reservoir downstream of the facility. Statistical analysis indicated metals are not related to runoff, but no possible source of metals was identified in the study (HDR, 1995).

In the Upper Mokelumne River watershed, a variety of existing land management activities have the potential to contribute to surface water contamination. As identified by local water agencies, these activities include development, forest practices, waste management and disposal, future water development, agriculture, herbicide/pesticide use, wildfire, livestock/grazing, mining, fish and wildlife, road construction, recreation, off-road vehicle use, fish farming, and authorized diversions. As stated in the *1995 Mokelumne River Watershed Sanitary Survey* (HDR, 1995), key issues that warranted the most concern in the watershed were wastewater discharges and land disposal, septic tanks, logging and forestry practices, urban development and storm runoff from urban growth areas, road building, livestock grazing in riparian zones, wildfire, and recreation and off-road vehicle use. Water management practices (which include existing hydroelectric facilities) were not identified as a contributor to surface water quality conditions, and no recommendations specific to operation of Pacific Gas and Electric Company facilities' operation were identified (HDR, 1995).

The Lower Mokelumne River (Comanche Reservoir to Delta) is included on the 1998 California CWA 303(d) TMDL list for copper and zinc associated with abandoned mines, and on the Basin Plan Water Quality Limited Segments list, but the upper watershed where Project Lands are located are not included on either list (CVRWQCB, 1998; USEPA, 1999). The current CWA 401 certification was issued in 1976.

The water purveyors in the Mokelumne watershed recognize the future potential for increased land uses and development and the potential effect on water quality. The 1995 *Mokelumne River Watershed Sanitary Survey* identifies several recommendations to address the key issues identified above. General recommendations for the entire watershed system include, but are not limited to: improvements in monitoring and enforcement of septic tank regulations; water quality testing above and below harvested areas; encouraging landowners with legal control authority to restrict or control road building that initiates or accelerates soil erosion; developing measures to minimize livestock grazing in riparian corridors; monitoring/minimizing the effects of recreational use in sensitive watershed areas; conducting surveys and monitoring following flooding, landslides, wildfires, spills, and waterborne disease outbreaks; and minimizing fire potential and pesticide spraying (HDR, 1995).

EBMUD is concerned about the quality of inflows to Pardee Reservoir and their impact on reservoir water quality. EBMUD notes that the Lower Mokelumne River is listed on the 303(d) list for copper and zinc. However, the 303(d) listing notes that the source for these pollutants is abandoned mines, which will not be affected by the project. EBMUD also raised questions about potential project related impacts on water quality as a result of reservoir operations at Blue Lakes and Salt Springs Reservoir.

Groundwater. No information was collected about groundwater in the Mokelumne River Bundle. The Hydroelectric Generating Facilities in this bundle do not use groundwater.

Bundle 14: Stanislaus River

The Stanislaus River Bundle consists of FERC No. 2130 (the Spring Gap and Stanislaus Hydroelectric Generating Facilities and associated appurtenances), and FERC No. 1061 (the Phoenix Hydroelectric Generating Facility and associated appurtenances). These assets are being bundled together to maintain FERC licenses No. 2130 and 1061, which share overlapping boundaries. In addition, these facilities are hydrologically linked, which will be maintained under this bundling.

Spring Gap-Stanislaus (FERC 2130)

The Drainage Basin and Water Sources. The Spring Gap-Stanislaus System lies within the Middle Fork and South Fork Stanislaus Rivers, two branches of the Stanislaus River that drain the western slope of the Sierra Nevada, in Tuolumne County. The asset consists of two hydroelectric generating facilities, with powerhouses located on the Middle Fork Stanislaus River (MFSR) and the Stanislaus River, and an interbasin transfer occurring between the South Fork and Middle Fork. The Spring Gap facility captures water in the South Fork Stanislaus River (SFSR) basin. The headwaters of the SFSR lie in the Emigrant Wilderness at an elevation of approximately 8,200 feet. The drainage area for the portion of the basin captured by the Spring Gap facility is 48.5 square miles, as determined directly downstream of the Philadelphia Diversion Dam (USGS, 1997). The Stanislaus facility captures water in the MFSR. The headwaters of the MFSR lie along the Sierra Nevada crest at an elevation of approximately 10,000 feet. The Stanislaus facility lies in the lower portion of the MFSR basin, with a drainage area of 332 square miles, as determined directly downstream of the Sand Bar Diversion Dam (USGS, 1997).

Hydroelectric Facilities. The asset consists of the Spring Gap and Stanislaus hydroelectric generating facilities. Each facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-12.

Water Management. Water use in these two branches of the Stanislaus River is coordinated by a series of hydroelectric facilities operated by Pacific Gas and Electric Company and Tri-Dam. Tri-Dam's facilities consist of the following FERC-licensed facilities: Beardsley/Donnells (FERC No. 2005), Tulloch (FERC No. 2067), and Sand Bar (FERC No. 2975). Pacific Gas and Electric Company has a power purchase agreement with Tri-Dam for the Beardsley/Donnells and Tulloch Facilities. Pacific Gas and Electric Company has a QF Contract with the Tri-Dam Power Authority (TDPA) concerning operations of the Sand Bar Facility (Interim Standard Offer No. 4) (Sand Bar ISO#4) (PG&E Co., 1999). Each of Tri-Dam's facilities and Pacific Gas and Electric Company's Spring Gap-Stanislaus System are highly interdependent from both an operational and regulatory standpoint. Operation of the facilities is based on a number of weather and contractual factors, including:

- prevailing water conditions,
- FERC license articles,
- the Tri-Dam Contract,
- the Sand Bar ISO#4,
- the New Melones Dam and Reservoir and Tulloch Dam and Reservoir Contract, and
- the Agreement between Pacific Gas and Electric Company and Tuolumne County.

The Spring Gap facility begins at Strawberry Reservoir (also known as Pinecrest Lake), an 18,312-af gross capacity storage facility located at approximately 5,600 feet on the SFSR. Water is released from the reservoir into the SFSR, where it travels approximately 4 miles before a maximum of 56 cfs is diverted into the Philadelphia Canal at the Philadelphia Diversion Dam. Streamflow in the SFSR downstream of Strawberry Dam varies seasonally due to spills and releases from the dam, but has averaged 124 cfs between 1938 and 1996.

As part of the FERC license requirements, there are minimum flows that must be maintained in the major streams below Pacific Gas and Electric Company facilities. These are summarized in Table 4.3-34 and further described in the following text.

FERC License Article 29 requires that the water surface of Strawberry Reservoir be maintained at the maximum elevation possible, consistent with operational demands, during the period of June 1 through September 15. At all other times, the minimum pool in the reservoir must provide a surface area of at least 10 acres, with a depth of not less than ten feet. After September 15 the reservoir is drafted to maximize the operation of Spring Gap Powerhouse and to meet the contractual irrigation water demands at Lyons Reservoir (FERC No. 1061). Historically, Pacific Gas and Electric Company has retained approximately 3,000 to 3,500 acre feet (af) of additional storage in the reservoir during winter months to provide flushing flows for the Philadelphia Ditch during periods

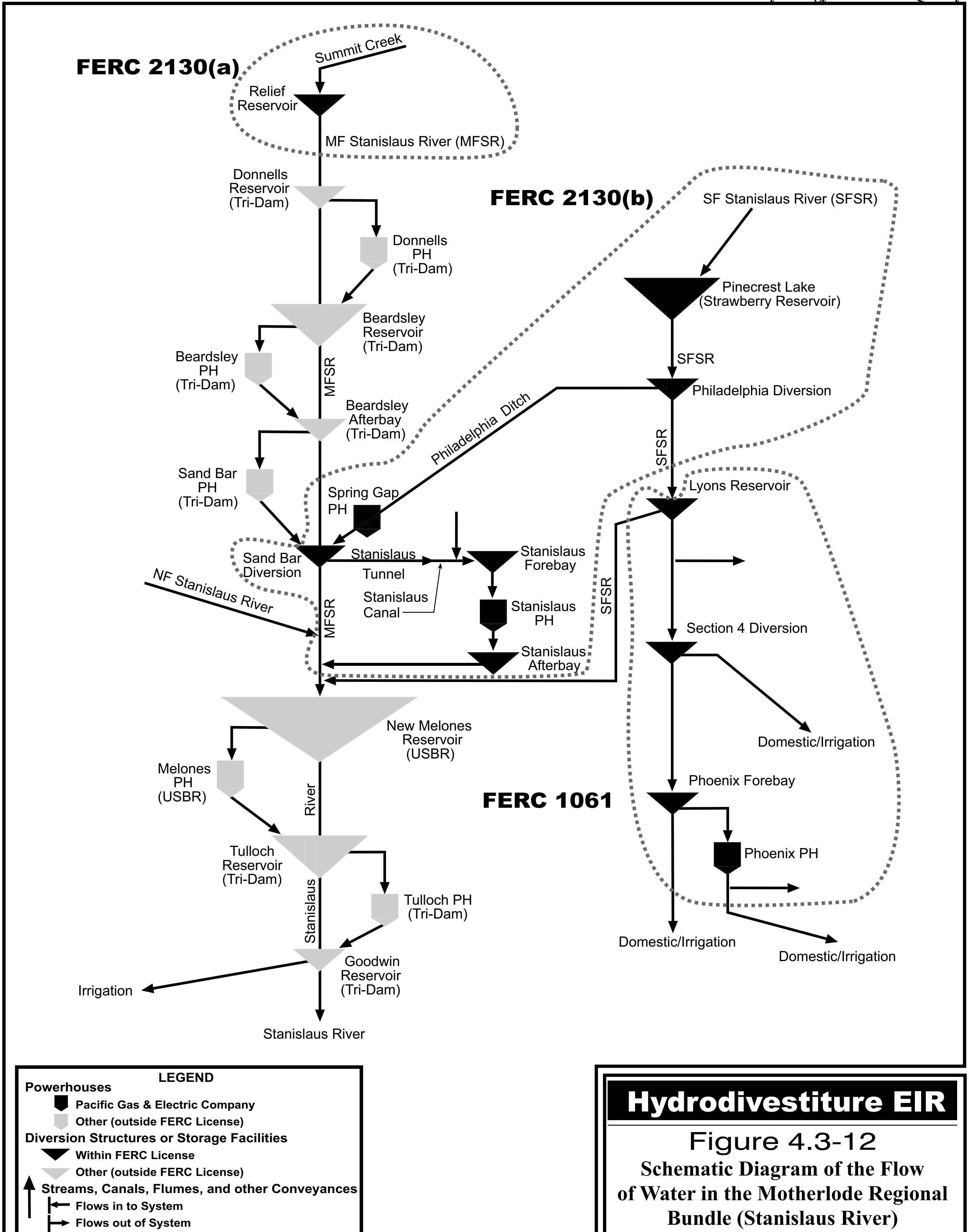
Table 4.3-34 Minimum Releases Associated with Stanislaus River System

Facility	Time Period	Minimum Release (cfs)
Strawberry (Pinecrest) Reservoir	Year Round	5508.7 af after 9/15 drawn down to min. storage [a]
South Fork Stanislaus River below Strawberry Dam	Year Round	None
South Fork Stanislaus River from Philadelphia Diversion dam to Lyons Reservoir	5/1-10/31 11/1-4/30	6 3
Relief Reservoir	Year Round	5 feet above outlet structure [b]
Middle Fork Stanislaus River from Summit Creek confluence to Donnells Reservoir[7/]	5/1-10/31 11/1-4/30 Year Round	10 (normal year) 5 (normal year) 5 (dry year)
Middle Fork Stanislaus River from Beardsley afterbay	Year Round	135 (normal year) 50 (dry year)
Middle Fork Stanislaus River below Sand Bar Flat dam	5/1-10/31 11/1-4/30 Year Round	50 (normal year) 25 (normal year) 25 (dry year)
Lyons Reservoir		FERC mandated ramping rate [c]
South Fork Stanislaus River below Lyons Reservoir	October Nov-June July Aug-Sep Year Round	8 (normal year) 10(normal year) 8(normal year) 5(normal year) 5 (dry year)
South Fork Stanislaus River below Tuolumne Canal diversion	Article 105 Minimum streamflow [d]	

[a] Under Article 29 “The licensee shall, consistent with operational demands, maintain the maximum water surface elevation in Strawberry Reservoir during the period from June 1 to September 15 and maintain a minimum pool of about 10 acres with a depth of not less than 10 feet at all other times, except under emergency conditions”.
[b] The reservoir is filled during spring runoff and is full or near full by June and/or July. After July, the reservoir is drawn down uniformly to minimum pool level in late December. There are no specific agreements that govern the rate at which Pacific Gas and Electric Company draws the Relief Reservoir down in the fall or refills it in the spring.
[c] Article 405 amended and states the licensee limit the maximum rate of change in the river flow (ramping rate) in the bypass reach of the SFSR so not to exceed 50 percent of the existing flow per hour, as measured at the streamflow gage required by the article 406. The ramping rate requirement pertains to controlled flows and to reduction of instream flows following an emergency release of water. The ramping rate criteria do not apply to spill conditions. Controlled flow conditions are deemed to be in effect when the elevation drops to 6 inches below the top of the flashboards at Lyons Dam.
[d] Refer to Article 105.
Source: PG&E Co., 1999

of heavy snowfall or freezing temperature. There are no specific agreements that govern the rate at which Pacific Gas and Electric Company drafts or fills Strawberry Reservoir.

The Philadelphia Canal runs 4.7 miles along the north side of the South Fork Stanislaus River Canyon to the Spring Gap Forebay. The mean annual flow in the canal between 1938 and 1996 was 41.6 cfs. From the forebay the water falls through the penstock leading to the Spring Gap Powerhouse, which operates as a baseload facility. The maximum capacity of the powerhouse is 59 cfs. Tailrace waters flow into the Sand Bar Diversion pool on the MFSR. Normal maximum gross head at the facility is 1,865 feet (PG&E Co., 1998E).



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Hydrodivestiture EIR

Figure 4.3-12

Schematic Diagram of the Flow of Water in the Motherlode Regional Bundle (Stanislaus River)

Aspen Environmental Group

FERC License Article 28 requires a minimum flow release below Philadelphia Diversion of six cfs during May through October, and three cfs during November through April.

The Stanislaus facility draws water from the Sand Bar Diversion pool, which is fed by discharge from the Spring Gap Powerhouse (7 MW) and inflow from the MFSR. Inflow into the diversion pool is regulated by a series of upstream storage reservoirs, including: (1) Pacific Gas and Electric Company's Relief Reservoir, (2) Tri-Dam's Donnells and Beardsley Reservoirs and Beardsley Afterbay on the MFSR, and (3) Pacific Gas and Electric Company's Strawberry Reservoir on the SFSR. As described above, regulated inflow from Strawberry Reservoir constitutes an inter-basin transfer of water. Pacific Gas and Electric Company's Relief Reservoir lies within the MFSR drainage, 33 miles upstream of the Sand Bar Diversion, and above the three Tri-Dam reservoirs.

Draining a watershed of 24.4 square miles on Summit Creek, Relief Reservoir has a gross storage capacity of 15,554 af. Water released by Pacific Gas and Electric Company from Relief Reservoir flows into the MFSR and through the Tri-Dam's Donnells and Beardsley reservoirs prior to reaching Sand Bar Diversion. Pacific Gas and Electric Company releases water from the diversion pool into the 11.2 mile-long Stanislaus Tunnel with a maximum capacity of 530 cfs.

The manner in which Pacific Gas and Electric Company manages water resources at Relief Reservoir is governed primarily by FERC license articles and operating agreements with Tri-Dam. During winter months, Pacific Gas and Electric Company maintains a minimum reservoir elevation five feet above the outlet structure to prevent ice damage. The reservoir is filled during spring runoff and is full or near full by June and/or July. After July, the reservoir is drawn down uniformly to minimum pool level in late December. There are no specific agreements that govern the rate at which Pacific Gas and Electric Company draws the Relief Reservoir down in the fall or refills it in the spring. However, Pacific Gas and Electric Company attempts to optimize the reservoir operations for downstream facilities. Pacific Gas and Electric Company's reservoir management is also partly controlled by minimum and maximum release requirements. As required under FERC License Article 25, Pacific Gas and Electric Company operates the reservoir to provide at least ten cfs in the Middle Fork Stanislaus River between May 1 and October 31, and at least five cfs between November 1 and April 30. During dry years, Pacific Gas and Electric Company provides five cfs minimum year round.

FERC License Article 27 requires a minimum release of 50 cfs during May through October, and 25 cfs during November through April from Sand Bar Diversion to the MFSR.(FERC, 1986) In addition, FERC License Article 30 requires avoidance of sudden releases of large flows at Stanislaus Afterbay Dam, and recommends downstream releases gradually changing over at least a one-hour period. (FPC, 1960)

Water in the Stanislaus Tunnel enters the facility forebay and penstock, then passes through the Stanislaus Powerhouse (91.0 MW), where it is discharged into the Stanislaus River just downstream of the confluence of the MFSR and North Fork Stanislaus River. Stanislaus Powerhouse has a maximum capacity of 830 cfs, and is used as a peaking facility. Since the inception of the California energy market, the powerhouse has been frequently called upon by the Cal-ISO to provide ancillary services to help balance demand and supply differences.

The Spring Gap Development is operated as a run-of-the-river (ROR) facility due to the lack of storage at Philadelphia Diversion (Northrup Et Al, 1997). ROR facilities limit the ability of the operator to engage in certain generation strategies such as peaking and provision of some ancillary services.

Water Delivery and Domestic Use. Pacific Gas and Electric Company's operation of Strawberry Reservoir is constrained by contractual obligations to the Tuolumne Utility District (TUD). TUD has a contractual right to request that Pacific Gas and Electric Company release water from the reservoir to meet downstream water needs. Pacific Gas and Electric Company has a senior water right at Lyons Reservoir (downstream of the Philadelphia Diversion on the South Fork Stanislaus River), but if additional water is required by TUD at the reservoir, Pacific Gas and Electric Company is obligated to draft Strawberry Reservoir and spill the water past the Philadelphia Diversion. TUD's requested releases from the Strawberry Reservoir are, in normal water years, 3,000 af between October and December (Northrup et al, 1997)

Water Quality. The beneficial uses associated with the Stanislaus River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the upper Stanislaus River to New Melones Reservoir are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat (COLD)
- Wildlife Habitat (WILD)

In general, water quality is considered to be good at all FERC-licensed water bodies. Temperature studies have been conducted in the Middle Fork Stanislaus River downstream of the Sand Bar Diversion Dam. Modeling studies conducted by Pacific Gas and Electric Company were used, in part, by FERC to establish the 50 cfs summertime minimum release from the Sand Bar Diversion. The minimum flow releases made at the dam were designed to maintain acceptable temperatures for trout in the upper two-thirds of the diverted reach (FERC, 1986). However, SWRCB staff note that water temperature standards for the protection of the COLD beneficial use that were in place when the existing licenses were issued, may not be considered acceptable to the certifying agency today or in future relicensing (SWRCB, 2000).

Water quality monitoring within the Stanislaus River watershed primarily consists of raw water monitoring at seven treatment plant locations, including one at Pinecrest Lake. The raw water intake is located at the bottom of the lake. Monthly raw water turbidity data for the period January 1993 to April 1995 remained relatively constant at approximately 0.08 NTU; the highest reported level was less than two NTU (see Table 4.3-35 below). No continuous upstream to downstream trends are apparent in turbidity data for the five intakes along the Stanislaus River system. Rather, local upstream conditions appear to mainly influence turbidity levels. Data for other constituents throughout the system is limited, but available data indicate low levels of metals probably due to natural sources (Brown and Caldwell, 1995).

The Lower Stanislaus River (Tulloch Reservoir to Delta) is included on the 1998 California CWA 303(d) TMDL list for pesticides associated with agricultural operations, and on the Basin Plan Water Quality Limited Segments list, but the upper watershed where Project Lands are located is not included on either list (CVRWQCB, 1998; USEPA, 1998). Pacific Gas and Electric Company does not perform turbidity monitoring in the Stanislaus River system. There is no current or pending CWA 401 certification.

Table 4.3-35 Ranges of Water Quality Parameters for the Stanislaus River

Parameter	Sampling Location		
	Pinecrest WTP (South Fork)	Lake Alpine WTP (North Fork above confluence with Middle Fork)	Ebbets Pass WTP (North Fork above confluence with Middle Fork near Utica Ditch)
Turbidity (NTU)	0.08	0.1	0.17 – 1.1
Total Dissolved Solids (mg/l)	27	48.2 - 109	5 - 80
pH	6.8	7.0 – 7.5	6.9 – 7.2
Alkalinity (as CaCO3) (mg/l)	10	20 – 26.4	11 – 13
Hardness (as CaCO3) (mg/l)	3	35.6 – 40.0	12 – 32
Cl (mg/l)	5	2 – 8.4	<2.0 – 3.5
Fe (mg/l)	<0.10	<0.10	<0.040 – 0.38
Cu (mg/l)	<0.01	<0.01	<0.01 - <0.01
NO3 (mg/l)	<0.01	<0.20 – 0.25/	<0.05 - <0.05
Fecal Coliform (MPN/100ml)	--	<2.0 - 16	<2.0 – 180

*Samples are taken from above water treatment plant intakes
*Single numbers express the averages instead of a minimum-maximum range.
Source: Brown and Caldwell, 1995.

The Stanislaus River watershed above Knight's Ferry is the water supply source for several agencies. In the Stanislaus River watershed, a variety of existing land management activities have the potential to contribute to surface water contamination. The 1995 *Stanislaus River Watershed Sanitary Survey* identifies livestock grazing, recreation and off-highway vehicle use, timber harvest practices, wastewater treatment facilities, wildfires, septic systems, and urban runoff as the major sources of water contamination in the watershed. Of particular concern is failing septic systems.

The California RWQCB, Central Valley RWQCB, Tuolumne and Calaveras Counties are presently addressing this problem. Abandonment of failing septic systems and providing homes with sewer connections is helping to resolve this problem, and should reduce the number of failing septic systems. This is expected to lead to an improvement in surface water quality. Hydroelectric water management practices were not identified as a contributor to surface water quality conditions, and no recommendations specific to operation of Pacific Gas and Electric Company facilities' operation were identified in the survey. Erosion issues associated with landslides and wildfires are of special concern in the Stanislaus watershed, according to the sanitary survey. This area is extremely steep and rugged in areas adjacent to watercourses and landslides are common and the potential for wildfire is high. Local water purveyors' recommendations to mitigate for future increases in land development and related activities include, but are not limited to: establishing routine inspection program for septic tanks; limiting access or number of cattle; improvements in coliform monitoring; as residential areas expand or other significant projects are developed, the water supply agencies should be aware of the adequacy of urban runoff practices and wastewater systems used; monitoring of Pinecrest Lake during summer to determine recreational effects; and development of watershed monitoring program. (Brown and Caldwell, 1995).

Groundwater. No information was collected about groundwater in the Stanislaus River Bundle because it is not utilized by the Spring Gap-Stanislaus System.

Phoenix (FERC 1061)

The Drainage Basin and Water Sources. The Phoenix System uses water within the SFSR drainage, one of the three primary tributaries of the Stanislaus River that drain the west slope Sierra Nevada, in Tuolumne County. The headwaters of the SFSR lie in the Emigrant Wilderness at an elevation of approximately 8,200 feet. The drainage area for the portion of the basin upstream of Lyons Dam is 66.8 square miles (USGS, 1997). Because the system lies downstream of Pacific Gas and Electric Company's Spring Gap-Stanislaus facilities, which divert water from the SFSR to the MFSR, the volume of water used by the system is not proportional to the size of the upstream basin.

Hydroelectric Facilities. The asset consists of the Phoenix Hydroelectric Generating Facility. The facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-12.

Water Management. The source of water to the facility is the SFSR. Water from the river flows into the 6,224-af usable storage capacity Lyons Reservoir. The volume of water that enters the reservoir is governed by Pacific Gas and Electric Company's operation of the upstream Spring Gap-Stanislaus System. Thus, Pacific Gas and Electric Company operates the Strawberry Reservoir to meet the water needs of the Phoenix and Spring Gap-Stanislaus Systems and the Tuolumne Water System.

Water that is stored in Lyons Reservoir is released into the SFSR, where up to 52 cfs is immediately diverted into the Main Tuolumne Canal, a 15.4-mile-long conduit transporting water to the Phoenix Powerhouse Header Box and penstock. The capacity of the penstock is 33 cfs. The difference between the canal and penstock capacities (19 cfs) exists because water is diverted from the canal into two other Tuolumne Water System canals to meet local water supply needs. These canals are the Section 4 Ditch near the community of Twain Harte and the Columbia Ditch at the Phoenix Powerhouse Header Box. The Phoenix Powerhouse (2.0 MW) is operated as a baseload facility. It has a maximum capacity of 25 cfs. Normal maximum gross head is 1,187 feet (PG&E Co., 1998E) Water discharged from the powerhouse is further distributed for domestic supply or irrigation throughout other portions of the Tuolumne Water System.

A minimum flow of two cfs is released at the Main Tuolumne Diversion Dam into the SFSR, as required by FERC License Article 404 (FERC, 1992d). The water then transits 18.5 miles before merging with the waters of the Stanislaus River just upstream of the U.S. Bureau of Reclamation's New Melones Reservoir. Flows released from Lyons Reservoir are also subject to a FERC-mandated ramping rate (FERC License Article 405). The maximum rate of change is not to exceed 50 percent of existing flow per hour. This pertains to controlled flows and reduction of flows following an emergency release of water, but does not apply to spill conditions.

Water Delivery and Domestic Use. The Phoenix Facility is an integral part of the Tuolumne Water System, a water distribution system owned by the Tuolumne Utility District that provides agricultural and domestic supply water through much of Tuolumne County. Water stored in Lyons Reservoir that is released into the SFSR is partially diverted from the canal into two other Tuolumne Water System canals to meet local water supply needs. These canals are the Section 4 Ditch near the community of Twain Harte and the Columbia Ditch at the Phoenix Powerhouse Header Box. In addition, water discharged from the powerhouse is further distributed for domestic supply or irrigation throughout other portions of the Tuolumne Water System.

As described in Chapter 2, Pacific Gas and Electric Company has water rights in the Phoenix System. There are additional contracts for water delivery or supply.

Water Quality. The beneficial uses associated with the Stanislaus River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the upper Stanislaus River to New Melones Reservoir are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)

- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)

The water quality of surface waters in the area is generally good. Pacific Gas and Electric Company conducted comprehensive water quality sampling in 1979 at several locations within Lyons Reservoir and the SFSR. Lyons Reservoir stratifies during the spring and summer months, with surface and bottom temperatures ranging from 25 to 20°C and DO ranging from 7 to 4 mg/l. The reservoir has a neutral pH (6.5-7.2) and negligible nutrient concentrations (nitrate and total phosphorous). High levels of total suspended solids were measured in the reservoir, due in part to erosion by uncontrolled vehicular use around the lake perimeter. In response to a FERC requirement, Pacific Gas and Electric Company began monitoring siltation in Lyons Reservoir (FERC, 1979b).

River water quality conditions are similar to the lake conditions. DO concentrations at the three river sampling stations established by Pacific Gas and Electric Company were uniformly high (range 6.8-11.2 mg/l). River water temperatures exhibit a broad range depending upon location and season. Water temperatures upstream of the reservoir ranged from a low in April of 5.5°C to a high in August of 26.2°C. Water temperatures downstream of the reservoir were cooler, by contrast, due to cold hypolimnetic releases.

Pacific Gas and Electric Company is required by its FERC license to protect against sedimentation in the South Fork Stanislaus River below Lyons Reservoir. FERC has recently approved and mandated a sediment monitoring plan that includes photographic assessment of the sediment accumulation in the river as well as bathymetric studies to monitor sediment deposition in the reservoir. The plan requires that Pacific Gas and Electric Company file with FERC results of the sediment surveys every five years, and if necessary, a sediment removal plan will be developed (FERC, 1995). The CWA 401 Certification for this license was waived pursuant to FERC Order 464 but the project is still subject to a 401 certification for sediment removal.

Watershed management issues associated with the Phoenix facility are as described for Spring Gap-Stanislaus facilities.

Groundwater. No information was collected about groundwater within the Phoenix Bundle. The Phoenix Hydroelectric Generating Facility does not use groundwater.

Bundle 15: Merced River

The Merced River Bundle consists of FERC No. 2467 (the Merced Falls Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

Merced Falls (FERC 2467)

The Drainage Basin and Water Sources. The Merced Falls System is on the Merced River, which flows through Mariposa and Merced counties. While the Merced River headwaters reach elevations of up to 11,000 feet in the Sierra Nevada, the facility is located in the lower reaches of the river, as it flows into California's San Joaquin Valley. The drainage area above the facility is 1,061 square miles, as determined directly downstream of the Merced Falls Dam (USGS, 1997).

Hydroelectric Facilities. The asset consists of the Merced Falls Hydroelectric Generating Facility. The facility has a powerhouse, reservoir and/or diversion, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-13.

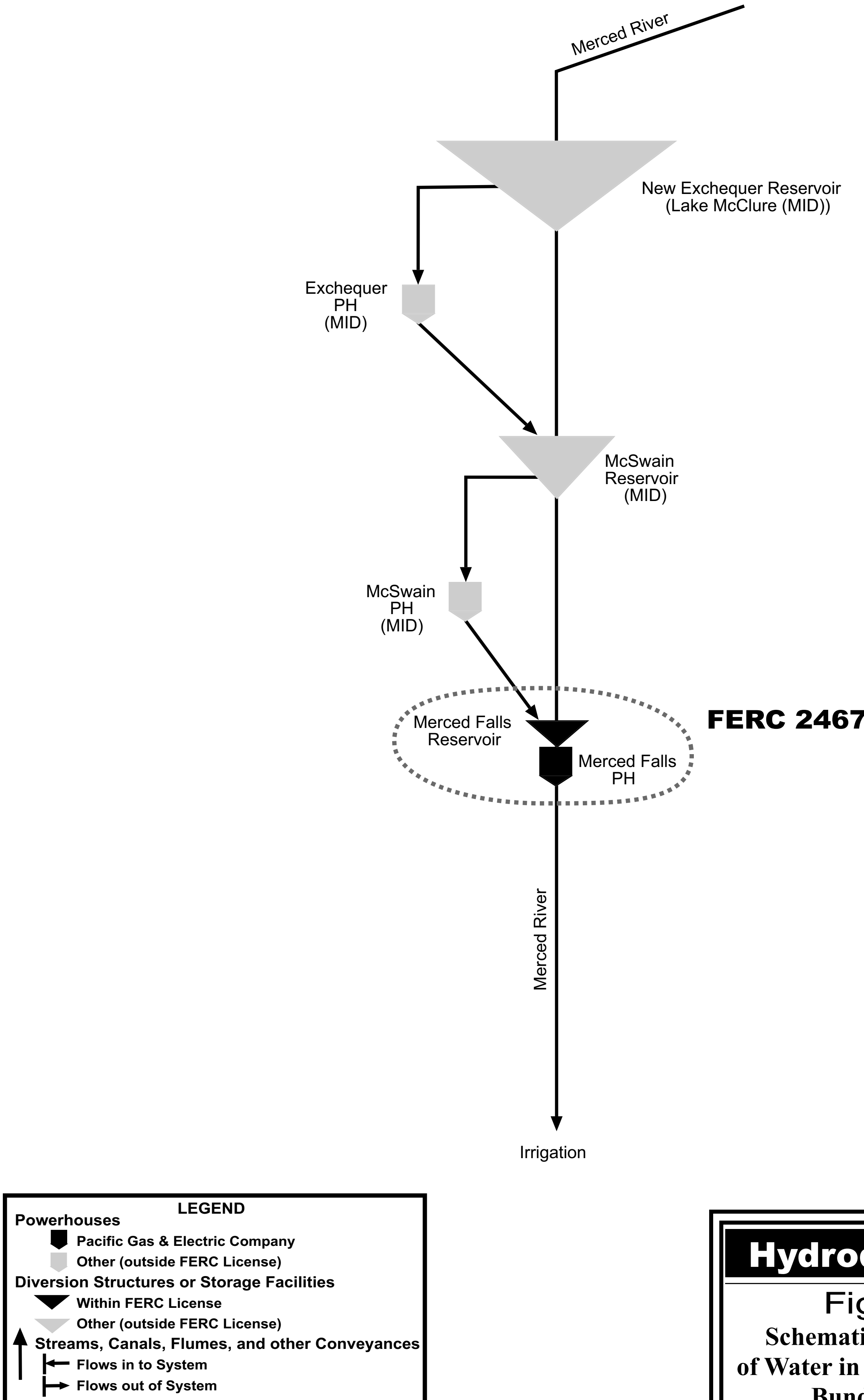
Water Management. The system lies directly downstream of two large reservoirs owned by the Merced Irrigation District (MID). MID's New Exchequer Reservoir (Lake McClure) has a usable storage capacity of 1,024,000 af, (PG&E Co., 1998d) providing the major storage and regulation capacity within the water system. MID's McSwain Reservoir, downstream of New Exchequer, has a capacity of 9,730 af. Pacific Gas and Electric Company has a power purchase contract with

MID that enables Pacific Gas and Electric Company to use MID water from the reservoirs to generate power at Merced Falls Powerhouse. Pacific Gas and Electric Company has a nonconsumptive right to divert up to 2,200 cfs from the Merced River (PG&E Co., 1929) Pacific Gas and Electric Company has no storage rights, (PG&E Co., 1929) meaning that all water entering the Merced Falls Reservoir passes directly from the river, through the powerhouse and back into the river.

Water stored in the reservoir is utilized by two powerhouses owned and operated by MID in partnership with Pacific Gas and Electric Company. Water discharged from the lower powerhouse (McSwain Powerhouse) is immediately impounded at Pacific Gas and Electric Company's Merced Falls Reservoir, a much smaller reservoir with a usable storage capacity of 603 af (FERC, 1987b) The Merced Powerhouse (3.5 MW) is operated by Pacific Gas and Electric Company as a baseload, ROR facility using water from the reservoir available at the point of the diversion (Camp Dresser & McKee, 1997). Normal maximum gross head at the powerhouse is 26 feet (PG&E Co., 1998E) ROR facilities limit the ability of the operator to engage in certain generation strategies such as peaking and provision of some ancillary services.

As part of the FERC license requirements, there are minimum flows that must be maintained in the Merced River below Merced Falls. Relevant license articles are noted in Table 4.3-36 and further described in the following text.

River flows are regulated by MID releases from New Exchequer and McSwain Reservoirs. Water is diverted at a normal maximum flow of 1,750 cfs through the Merced Falls Powerhouse, then discharged to the Merced River (PG&E Co., 1997b). When inflows exceed 2,200 cfs, the facility



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-13

Schematic Diagram of the Flow of Water in the Motherlode Regional Bundle (Merced River)

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Table 4.3-36 Minimum Releases Associated with Merced River System

Facility	Time Period	Minimum Release (cfs)
Merced River below Merced Falls Reservoir		Articles 35, 38,40,41, 42

Source: PG&E Co., 1999

spills water at either radial gates (inflow less than 12,250 cfs) or needle beams (inflow greater than 12,250 cfs) (Jansen, 1993). FERC License Article 35 stipulates that when maximum flood control releases are made from MID's upstream Exchequer Project (FERC No. 2179), the outflow from the Merced Falls System shall not exceed inflow (FERC, 1969).

While minimum flow releases required at the powerhouse range from 15 to 75 cfs depending upon season and water year type, mean monthly flows measured directly below the powerhouse have ranged from 398 to 2,318 cfs between 1925-1996 (USGS, 1997). FERC License Article 38 requires that Pacific Gas and Electric Company release minimum flows from the dam into the Merced River that are consistent with those designated in Articles 40, 41, and 42 of the FERC license held by MID for the Exchequer Project. In addition, a 1997 FERC Order recommends the continuation of minimum flows (FERC, 1997d).

***Water Quality*.** The beneficial uses associated with the Merced River are summarized in the 1998 Basin Plan for the Sacramento and San Joaquin River basins compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Merced River from McSwain Reservoir to the San Joaquin River are:

- Municipal and Domestic Supply (MUN)
- Agricultural Supply (AGR)
- Industrial Service Supply (IND)
- Industrial Process Supply (PROC)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat (COLD)
- Migration of Aquatic Organisms (MIGR)
- Wildlife Habitat (WILD)
- Spawning, Reproduction, and/or Early Development (SPWN)

It should be noted that some of the beneficial uses listed might apply only to areas downstream of Project Lands.

The small reservoir and high flows suggest that the reservoir does not stratify during summer months. Water temperatures in the mixed reservoir are dependent upon temperatures of water released from New Exchequer Reservoir that is likely to be cool due to hypolimnetic releases.

Lateral inflows to the Merced River in the northern part of Merced County are of very good quality, with low amounts of dissolved solids (Merced County, 1989).

FERC License Article 14 requires that Pacific Gas and Electric Company operate the system in a manner that minimizes soil erosion and siltation on lands adjacent to the stream (FPC, 1964). Within the language of this license article, FERC reserves the right to order the licensee to perform preventative measures to protect against these impacts.

Groundwater. No information was collected about groundwater in the Merced River Bundle as the Merced Falls Hydroelectric Generating Facility does not use groundwater.

4.3.4.5 Kings Crane-Helms Regional Bundle

The Kings Crane-Helms Region includes seven FERC licenses covering 13 powerhouses and the Helms pumped storage facility, with a combined capacity of 1,786.6 MW. There are five separate bundles located in the Kings Crane-Helms Region: Crane Valley, Kerckhoff, Kings River, Tule River and Kern River (see Figures 2-30 and 2-31 in Chapter 2). The following sections describe water resources for each of Pacific Gas and Electric Company's facilities in the Kings Crane-Helms Region. Specifically, these sections describe each drainage basin and the location of the facilities, describe how water is used at each facility, describe the flow of water through the different facilities, and describe water diversion and use by other beneficial users. These sections also provide a description of water conveyance systems and capacities, as well as maximum powerhouse capacity.

When applicable, the unique water use constraints, such as physical capacity constraints, storage constraints, and regulatory restrictions (e.g., instream flow release requirements) included in FERC licenses, are discussed for each facility. Schematic diagrams depict the flow of water.

Regional Setting

The Kings Crane-Helms Watershed Region is the most southern of Pacific Gas and Electric Company's hydropower areas spanning Madera, Fresno, Tulare and Kern counties. The area contains some of California's highest headwaters with mountain peaks exceeding 12,000 feet. The region includes seven FERC licenses covering 13 powerhouses, 20 dams on six streams and a total reservoir capacity of about 300,000 acre-feet. This area contains 1,787 MW of generating capacity, about 46percent of Pacific Gas and Electric's total hydropower capacity. The general layout of the Kings Crane-Helms facilities and the major hydrographic features within this regional bundle are shown in Figures 2-28 and 2-29 in Chapter 2.

The Crane Valley and Kerckhoff bundles lie in the San Joaquin River watershed, draining the western slope of the Sierra Nevada and ultimately flowing into Millerton Lake located on the main stem of the San Joaquin River. Bass Lake is the primary storage facility located on the North Fork of Willow Creek, a tributary to the San Joaquin River. Other smaller reservoirs serve as powerhouse forebays and afterbays. Annual precipitation at Auberry, near Crane Valley and Kerckhoff Assets, is about 25 inches. Natural (unregulated) flow hydrographs are dominated by spring snowmelt runoff, with the highest flows occurring during April through July. Baseflow is relatively low in the summer and early fall period.

The Kings River bundle, including the Helms Pumped Storage, Haas-Kings, and Balch assets, is located on the North Fork Kings River watershed, draining the western slope of the Sierra Nevada in Fresno County and ultimately flowing into Pine Flat Reservoir located on the main stem of the Kings River. The primary storage facilities in this bundle include Courtright and Wishon Reservoirs. Other smaller reservoirs serve as powerhouse forebays and afterbays. Precipitation at Huntington Lake, near the Helms Facility, is about 38 inches per year. Precipitation at the Balch Powerhouse is about 30 inches per year. Natural (unregulated) flow hydrographs are dominated by spring snowmelt runoff, with the highest flows occurring during the April through July period. Baseflow is relatively low in the summer and early fall period.

The Tule River Bundle, located on the North Fork of the Middle Fork Tule River, and the Kern Canyon Bundle, located on the Kern River, drain the western slope of the Sierra Nevada. These facilities operate as run-of-river projects. Precipitation at the Kern River Powerhouse is about nine inches per year. Natural (unregulated) flow hydrographs are dominated by spring snowmelt runoff, with the highest flows occurring during the April through July period. Baseflow is relatively low in the summer and early fall period.

Local Regulations and Policies

Operation of hydroelectric facilities can not degrade or impair water quality to the extent that beneficial uses are affected. Beneficial uses are determined by the State Water Resources Control Board and are documented in nine Regional Water Quality Control Plans (Basin Plans), along with water quality objectives, and an implementation plan for meeting water quality objectives and preserving beneficial uses. The facilities in the Kings Crane-Helms watershed are situated on rivers which lie in the Central Valley Region and are governed by the objectives and policies contained in two Basin Plans: the Water Quality Control Plan for the Tulare Lake Basin (1995) and the Water Quality Control Plan for the Sacramento/San Joaquin River Basins (1994). Pertinent information from these two plans, including designated beneficial uses, is discussed on a license-by- license basis in the following text.

Refer to Section 4.3.2 for additional information.

Bundle 16: Crane Valley

Crane Valley (FERC 1354)

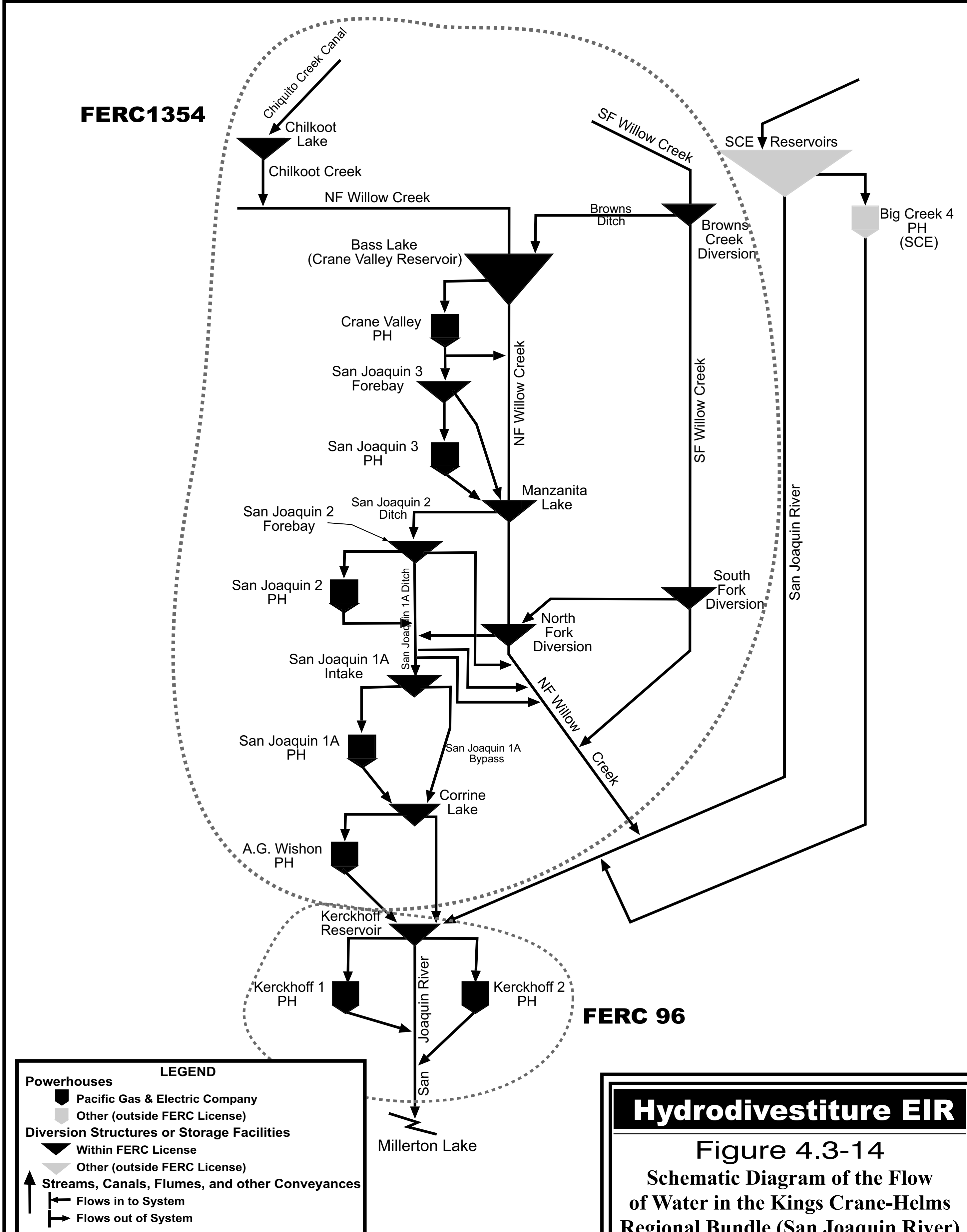
The Crane Valley Bundle consists of FERC No. 1354 (the Crane Valley, San Joaquin 3, San Joaquin 2, and San Joaquin 1A, and A.G. Wishon Hydroelectric Generating Facilities and associated appurtenances). These generating facilities are being bundled together to maintain FERC No. 1354 license.

The Drainage Basin and Water Sources. The Crane Valley System, located in Madera County, lies within the North Fork Willow Creek (NFWC) basin, a tributary to the San Joaquin River, and drains the western slope of the Sierra Nevada. The headwaters of NFWC originate in Madera County near White Chief Mountain at an elevation of 8,676 feet. Except for the Pick Up Ditch, which is a transbasin diversion delivering water from Chiquito Creek to Chilkoot Reservoir, the storage and diversion facilities are located on the North Fork and South Fork of Willow Creek (SFWC) and their tributaries (PG&E Co., 1997B). The drainage area within the Willow Creek basin that is utilized by the system is 61 square miles, as measured at the A.G. Wishon Powerhouse (PG&E Co., 1986a).

Hydroelectric Facilities. The system consists of five powerhouses that are fed mainly by water stored in Bass Lake, located about 42 miles east of Fresno. Hydroelectric facilities include of the Crane Valley Powerhouse, the San Joaquin #3, San Joaquin #2, San Joaquin No. 1A, and the A.G. Wishon Powerhouses, water conveyance facilities, a switchyard and associated buildings, Bass Lake (or Crane Valley Reservoir), the Crane Valley Dam, Chilkoot Lake and Dam, and the Browns Creek diversion dam. Chilkoot Lake is approximately eight miles northeast of Bass Lake and is primarily fed by Chilkoot Lake Pick-Up Ditch, a rock channel that diverts runoff from Chiquito Creek. In addition to Chilkoot Lake and Bass Lake, key reservoirs in this system include Manzanita Lake and Corrine Lake (as shown in Figure 4.3-14) shows the key hydroelectric facilities, reservoirs, and associated appurtenant structures (for example, conduits and penstocks) associated with this system.

Water Management. Water use at the Crane Valley System begins at Chilkoot Lake, the highest feature at 7,497 feet. In addition to impounding Chilkoot Creek water, the 308-af lake also collects water that is diverted from nearby Chiquito Creek through a 0.7-mile-long ditch. In the late spring of every year, water is released from Chilkoot Lake to Chilkoot Creek, a tributary to NFWC, where it flows into North Fork Willow Creek and eventually into Bass Lake. Water from Brown's Creek, a tributary to the SFWC is diverted to Bass Lake via the Browns Creek Diversion Dam and the 2.6-mile Browns Creek Conduit. This diversion continues throughout the year, except during periods of very low flow in mid-to late-summer, when no diversion occurs. Mean annual flow in the conduit between 1987 and 1996 was 20.2 cfs. Other tributaries to Bass Lake include Slide Creek, Pines Creek, Salter Creek, and one unnamed tributary (PG&E Co., 1986d).

The Crane Valley System is currently in the relicensing process. Although not required to do so by the existing FERC license, Pacific Gas and Electric Company releases four cfs of water into Brown's Creek, a tributary to the SFWC, from the Diversion Dam. While this release is currently performed on a voluntary basis, it is expected to become the required minimum flow when the new



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-14

Schematic Diagram of the Flow of Water in the Kings Crane-Helms Regional Bundle (San Joaquin River)

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FERC license is issued. However, as this release is currently voluntary a new owner, or Pacific Gas and Electric Company, could reduce or eliminate it.

The 3,376 foot-elevation Bass Lake (Crane Valley Reservoir) is the main storage reservoir of the system, with a drainage area of 50.4 square miles and a gross storage capacity of 45,410 af. Bass Lake serves as the forebay to the Crane Valley Powerhouse (0.9 MW). Water released from Bass Lake flows to the Crane Valley Powerhouse through a 550-foot-long tunnel and a 198-foot-long penstock, with a maximum capacity of 165 cfs. Normal maximum gross head at the facility is 128 feet (PG&E Co., 1998d).

Bass Lake operation is influenced by a contractual agreement known as the Miller and Lux Agreement, which is presently administered by the U.S. Bureau of Reclamation (USBR). Under the terms of this agreement, Pacific Gas and Electric Company is permitted to store water up to certain elevation levels at different times of the year for power generation purposes. The USBR can also order the release of Bass Lake water during certain times of the year, primarily fall and winter, in response to downstream water users who have senior water rights on the San Joaquin River. Management guidelines for recreational use and facilities at Bass Lake are outlined in the 1989 Water Surface Management Plan (PG&E Co., 1989c). This plan is a multi-agency agreement between the USFS, Madera County and Pacific Gas and Electric Company designed to improve safety and visitor experience.

In recent years, the Bass Lake Homeowners Association and Pacific Gas and Electric Company have requested a variance under the Miller and Lux Agreement to allow Pacific Gas and Electric Company to keep Bass Lake at a higher elevation for more of the year to benefit recreational users. The USBR has agreed to the variance, but only on a year-by-year basis. These variances have somewhat altered the pattern of water use at Bass Lake.

The rights to water in the Willow Creek drainage basin are partially held by Pacific Gas and Electric Company and MID. Pacific Gas and Electric Company can use water that MID owns for power generation, but Pacific Gas and Electric Company must pay MID for this use under the terms of a 1984 agreement between the two parties (PG&E Co., 1984). These constraining variables limit the manner in which Pacific Gas and Electric Company uses water in the basin.

Although not required to do so by the existing FERC license, Pacific Gas and Electric Company releases a minimum flow of one cfs below Crane Valley Powerhouse into the NFWC. As with the release from Browns Creek Diversion Dam, this 1 cfs release is currently made voluntarily. The new FERC license may establish a permanent minimum flow requirement for this site. SWRCB staff note that there are times when the current voluntary one cfs release is not adequate to protect aquatic resources in NFWC. Spring spill flows augment the release, resulting in a mean annual flow of 15.1 cfs in NFWC during the period between 1941 and 1996.

After passing through the Crane Valley Powerhouse, water is conveyed approximately 3.5 miles through the San Joaquin No. 3 Conduit (a series of canals, flumes and tunnels) to the 19-af San Joaquin No. 3 Forebay. Mean annual flow in the conduit for the time period 1941 to 1996 was 68.9 cfs, although its maximum capacity is 160 cfs. From the San Joaquin No. 3 Forebay, water is diverted through a 3,028-foot-long penstock to the 164-cfs-capacity San Joaquin 3 Powerhouse (4.2 MW). Normal maximum gross head of the powerhouse is 405 feet (PG&E Co., 1998E). The San Joaquin No. 3 Powerhouse tailrace water is discharged into Manzanita Lake, which provides storage for the San Joaquin No. 2 Powerhouse (3.2 MW). The 164-af lake also receives the flow directly from NFWC.

Water from Manzanita Lake is released into the San Joaquin No. 2 Conduit where it flows 2.91 miles to the 11-af San Joaquin No. 2 Forebay, then through the San Joaquin No. 2 Powerhouse. The San Joaquin No. 2 Conduit has a maximum capacity of 160 cfs, but normal maximum flow through the powerhouse is 148 cfs. Normal maximum gross head at the powerhouse is 307 feet (PG&E Co., 1998E).

Water discharged from the San Joaquin No. 2 Powerhouse immediately enters the San Joaquin No. 1 Conduit along with water diverted from the NFWC and the SFWC. The San Joaquin No. 1 Conduit has a capacity of 210 cfs and extends 4.83 miles, terminating at the San Joaquin 1A Powerhouse (0.4 MW). Normal maximum gross head of the powerhouse is 42 feet (PG&E Co., 1998E). Of the water in the San Joaquin No. 1 Conduit, a maximum of 167 cfs flows through the powerhouse, while the remaining water flows directly into the 69-af Corrine Lake. Tailrace water from the San Joaquin 1A Powerhouse also flows into Corrine Lake, which is the forebay to the A.G. Wishon Powerhouse (20.0 MW).

Water is diverted from the lake directly from Corrine Lake to the powerhouse. Normal maximum gross head of the facility is 1,412 feet (PG&E Co., 1998E). The powerhouse discharges up to 235 cfs into the headwaters of Kerckhoff Lake, part of the Kerckhoff System (FERC No. 96).

All of the powerhouses in the Crane Valley System are operated as baseload facilities, because flows must be carefully balanced through the relatively small capacity reservoirs and canals downstream of Bass Lake.

Water Quality

Beneficial uses associated with the Willow Creek Basin are summarized in the 1994 Water Quality Control Plan for the Central Valley Region compiled by the Regional Water Quality Control Board, Central Valley Region (CRWQCB-CVR). The beneficial uses of the San Joaquin River from its sources to Millerton Lake, which includes the Willow Creek Basin, include:

- Municipal and Domestic Supply (MUN)
- Irrigation and Stock Watering (AGR)
- Hydropower Generation (POW)

- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)

The Crane Asset is currently undergoing relicensing. As part of the relicensing process, Pacific Gas and Electric Company has conducted a number of studies of water quality conditions in Bass Lake, the North Fork Willow Creek (NFWC), South Fork Willow Creek (SFWC) and the Willow Creek mainstem. The results of these studies are primarily documented in Pacific Gas and Electric Company's Application for New License and the FERC's Environmental Assessment. Tables 4.3 37 and 4.3-38 provide ranges of values for some important water quality parameters in Bass Lake and in NFWC, SFWC and Willow Creek:

Table 4.3-37 Ranges of Water Quality Parameters for Bass Lake at Three Depths

Parameter	Depths			Basin Plan Standard
	3 Feet	49 Feet	75 to 95 Feet	
Temperature (°C)	8.3 – 25.5	6.7 – 11	5.9 – 8	-
Dissolved Oxygen (mg/l)/Saturation (%)	7.0 – 9.8 / 93% - 115%	3.2 – 9.4 / 33% - 89%	0.7 – 9.2 / 7% - 84%	Narrative*
Total Dissolved Solids (mg/l)	16.0 - 36.0	24.0 - 40.0	12.5 - 34.0	-
Total Suspended Solids (mg/l)	1.1 – 4.7	1.0 – 12.6	1.4 – 6.4	-
Conductivity (umhos/cm at 25°C)	29.0 – 54.0	29.0- 44.0	31.0 – 45.0	-
pH	6.4 – 7.5	7.0 – 8.1	7.5 – 8.0	6.5 – 8.5
Alkalinity (as $CaCO_3$) (mg/l)	12.0 – 17.0	12.0 – 17.0	<0.5 – 19.0	-
Hardness (as $CaCO_3$) (mg/l)	6.5 – 11.0	7.0 – 11.8	8.5 – 11.4	-
Fe (mg/l)	0.03 – 0.042	0.02 – 0.053	0.02 – 0.58	0.3
Cu (mg/l)	<0.001	<0.001 – 0.001	<0.001 – 0.001	0.01
NH_4 (mg/l)	0.02	<0.01 – 0.02	0.01 – 0.07	-
NO_3 (mg/l-N)	0.02 – 0.08	0.02 – 0.05	0.06 – 0.14	10.0
PO_4 (mg/l)	<0.01 - <0.02	<0.01 - <0.02	<0.01 - <0.02	-
Chlorophyll *a* (ug/l)	1.4 – 1.6	0.7 – 2.6	0.2 – 2.6	-
Fecal Coliform (MPN/100ml)	<2 - 5	<2 - 4	<2	200

Source: PG&E Co., 1986a

Table 4.3-38 Ranges of Water Quality Parameters for North Fork Willow Creek, South Fork Willow Creek and the Willow Creek Mainstem*

Parameter	Stream Segment			Basin Plan Standard
	NFWC	SFWC	Willow Creek	
Temperature (°C)	0.2 – 26.5	0.3 – 25	2 – 29	-
Dissolved Oxygen (mg/l) / Saturation (%)	7.5 – 11.3 / 90% - 108%	7.8 – 12.6 / 86% - 102%	8.7 – 11.6 / 95% - 112%	7.0
Turbidity (NTU)	1.4 – 34.0	0.37 – 4.3	0.5 – 1.4	-
Total Dissolved Solids (mg/l)	32 - 100	29 - 66	44 - 82	-
Total Suspended Solids (mg/l)	0.6 – 13.7	0.4 – 7.4	1.6 – 7.0	-
Conductivity (umhos/cm at 25°C)	36.0 – 144.0	20.0 – 65.0	18.2 – 48.0	-
pH	6.8 – 7.7	6.8 – 7.6	7.5 – 7.6	6.5 – 8.5
Alkalinity (as $CaCO_3$) (mg/l)	11.0 – 93.0	10.0 – 62.0	18.0 – 21.0	-
Hardness (as $CaCO_3$) (mg/l)	10.0 – 45.5	5.2 – 17.1	11.4 – 25.7	-
Cl (mg/l)	<0.1 – 19.0	0.2 – 13.0	1.5 – 1.9	-
Fe (mg/l)	0.1 – 0.42	0.01 – 0.26	0.02 – 0.13	0.3
Cu (mg/l)	<0.001 – 0.008	<0.001 – 0.002	<0.001 – 0.001	0.01
NH_4 (mg/l)	<0.01 – 0.10	<0.01 – 0.08	<0.01 – 0.08	-
NO_3 (mg/l)	0.02 – 0.49	0.01 – 0.10	0.01 – 0.03	10.0
PO_4 (mg/l)	<0.01 – 0.11	<0.01 – 08 .08	<0.01 – 0.02	-
Fecal Coliform (MPN/100 ml)	<2 - 49	2 - 49	2 - 70	200

*Ranges reported for NFWC and SFWC combine ranges from three and two stations, respectively
Source: PG&E Co., 1986a

The water quality in Bass Lake and the three segments of Willow Creek is generally good, but the maximum values for iron in Bass Lake and NFWC and the minimum value of pH in Bass Lake did not meet Basin Plan standards. These violations of the standards were due to natural factors.

Water temperature is the most important water quality issue in the Crane Valley area streams and reservoirs because it strongly affects aquatic biological resources. The maximum mean daily water temperatures at most locations in the bypassed reaches of NFWC, SFWC and the mainstem of Willow Creek for the period of June through October 1984 exceeded 20°C, which is a generally accepted maximum temperature standard for cold water habitat. The coolest temperatures were in SFWC above and below the Browns Creek Diversion and NFWC from Bass Lake to Manzanita Lake.

To estimate the degree to which increased flow could be used to reduce stream temperatures, Pacific Gas and Electric Company simulated water temperatures at different stream flow levels. The following table provides the results of the simulations, showing the percentage of different stream segments during a normal July with water temperatures below 20ºC at eight different flow levels.

With the current voluntary minimum flows of one cfs for NFWC of 4 cfs for SFWC, Pacific Gas and Electric Company simulations indicate that most of the NFWC and SFWC have cold water temperatures in July. Data for August and September were not available. Relatively little of the mainstem Willow Creek is simulated as having temperatures below 20ºC except when flows exceed five cfs. Note that under current operations, flow releases to the SFWC are less than four cfs when natural flow above Browns Diversion is less than four cfs, which occurs often in July.

Table 4.3-39 Simulated Water Temperatures versus Flow Rates – Percent of Stream Segments with Temperatures below 20ºC

Flow (cfs)	Stream Segment (length)					
	SFWC below Browns Creek Diversion (4.6 miles)	SFWC below Peckinpah Creek (1.8 miles)	NFWC below Bass Lake (3.3 miles)	NFWC below Manzanita Lake (3.1 miles)	Willow Creek from NFWC-SFWC confluence to Whisky Creek (4.4 miles)	Willow Creek below Whiskey Creek (2.0 miles)
0	100	58	43	100	17	0
1	100	66	70	100	5	0
3	100	85	98	100	41	0
5	100	100	100	100	56	0
7	100	100	100	100	72	0
10	100	100	100	100	89	0
25	100	100	100	100	100	70
50	100	100	100	100	100	100

Source: FERC, 1992

Water temperatures in Bass Lake also greatly affect fish. Bass Lake is coolest in January, when it has a constant temperature of about 4ºC throughout the water column. The lake begins to stratify in February and March and is fully stratified by June. Late summer temperatures in the epilimnion of the lake sometimes exceed 25ºC, which is lethally warm for cold water fish species. Therefore, during the summer and early fall, these fish move into the hypolimnion, which remains below about 10ºC. The lake begins cooling again in September and is fully mixed by October, with a uniform temperature of about 12ºC. Water is released to NFWC from the hypolimnion of Bass Lake, so the temperature of the hypolimnion greatly affects temperatures in the creek.

The DO levels in the hypolimnion of Bass Lake often fall well below four milligrams per liter by September, which may adversely affect fish. The current management practice of maintaining high lake levels in Bass Lake into the early fall probably increases the volume of the hypolimnion, which may help preserve adequate DO levels. Ongoing relicensing negotiations have reached agreement on a minimum storage level of 5,888 acre-feet (equivalent to a depth of 55 feet) designed to provide adequate cold water fishery habitat. This minimum may eventually be incorporated into the FERC license.

Groundwater. Groundwater in the watershed and at Willow Creek is not utilized by the Crane Valley System. Considering the known technical information on groundwater basins and the extent of their water supplies throughout the state, there are no known groundwater aquifers within the FERC-licensed area (PG&E Co., 1986d).

Bundle 17: Kerckhoff

Kerckhoff (FERC 96)

The Kerckhoff Bundle consists of FERC No. 96 (the Kerckhoff 1 and 2 Hydroelectric Generating Facilities and associated appurtenances), along with the Auberry Service Center. These generating assets are being bundled together to maintain the FERC No. 96 license.

The Drainage Basin and Water Sources. The Kerckhoff System lies within the upper San Joaquin River Basin, which drains the western slope of the Sierra Nevada, in Fresno and Madera Counties. The San Joaquin River is formed by the confluence of the North Fork and Middle Fork San Joaquin River (FERC, 1979c). All of the Kerckhoff storage and diversion facilities are located on the San Joaquin River. The drainage area within the San Joaquin River basin that is utilized by the Kerckhoff System is 1,461 square miles (PG&E Co., 1986a). This encompasses most of the 1,638-square-mile basin, which extends from Friant Dam, at an elevation of about 300 feet, to the crest of the Sierra Nevada.

Hydroelectric Facilities. The Kerkhoff system is located downstream of the Crane Valley assets, on the San Joaquin River, about 4 miles west of Auberry. As shown in Figure 4.3-14, the system includes a reservoir referred to as Kerkhoff Reservoir, two powerhouses referred to as Kerkhoff No. 1 and Kerkhoff No. 2, and appurtenant facilities. Kerkhoff Reservoir serves as the forebay for both Kerckhoff No. 1 and No. 2 powerhouses and has a usable storage capacity of approximately 4,252 af. The intake structures for both powerhouses are situated on the south side of the reservoir; two tunnels convey water from the intake structures to the Kerkhoff No.1 and No. 2 Powerhouses. Kerkhoff No. 1 Powerhouse has a total flow capacity of 1,735 cfs; Kerkhoff No. 2 Powerhouse has a total flow capacity of 5,100 cfs. After generating power, water is released back into the San Joaquin River, near the upper end of Millerton Reservoir, which is managed by the Bureau of Reclamation. The Bureau provides water for irrigation through a special agreement (Miller and Lux Agreement) with downstream water rights holders.

Water Management. Water used by this system originates in a series of high-elevation reservoirs on the San Joaquin River and Willow Creek. The Kerckhoff System is impacted by operations of two upstream hydroelectric developments: (1) the Crane Valley System (FERC No. 1354), and (2) Southern California Edison Company's Big Creek hydroelectric facilities. While the A.G. Wishon Powerhouse contributes up to 235 cfs of the flow, the greater percentage of flow in the San Joaquin River is controlled by the Big Creek facilities. The Big Creek system includes nine powerhouses and six storage reservoirs, beginning with Lake Edison and Florence Lake, located near the headwaters of the San Joaquin River. The Big Creek 4 Powerhouse is located a short distance upstream of Kerckhoff Reservoir.

Kerckhoff Reservoir impounds the flow released from the upstream powerhouses and has a usable storage of approximately 4,252 af. Reservoir water is used to generate power at the Kerckhoff 1 and 2 Powerhouses, and is released into the San Joaquin River for instream habitat. The Kerckhoff 1 Powerhouse (38 MW) receives water through a 3.2-mile-long tunnel. Maximum flow through the powerhouse is 1,735 cfs. Normal maximum gross head at the powerhouse is 350 feet (PG&E Co., 1998E). Water exiting the powerhouse returns to the San Joaquin River and flows for approximately 1.5 miles before entering Millerton Lake. A second 4.1-mile-long tunnel leads from Kerckhoff Reservoir to the Kerckhoff 2 Powerhouse (155 MW), with a maximum flow capacity of 5,100 cfs. Normal maximum gross head at the facility is 421 feet (PG&E Co., 1998d). Water leaving the Kerckhoff 2 Powerhouse discharges directly into Millerton Lake. Because the Kerckhoff 2 Powerhouse is capable of producing energy more efficiently with the water available, the Kerckhoff 1 Powerhouse is typically shut down, except during high flow periods, during Kerckhoff 2 Powerhouse annual maintenance, or when powerhouse releases are needed to provide certain instream habitat flows. The Kerckhoff 2 Powerhouse is generally used as a peaking plant, except during the spring spawning season of American shad, as explained below.

FERC License Article 45 requires a minimum instream flow release of 25 cfs during normal water years, and 15 cfs during dry water years from Kerckhoff Reservoir into the San Joaquin River (FERC, 1988). Additional releases may also be made in consultation with the CDFG, in order to maintain stream temperatures at or below 27°C upstream of Kerckhoff 1 Powerhouse (PG&E Co., 1981b). A 1993 FERC Order also establishes a flow regime during the May 15 through June 30 spawning season for the American shad. The shad require flowing water for spawning, so the backwater effects of Millerton Lake are overcome by increasing the flows from the Kerckhoff Powerhouses during spawning season. A variable minimum release schedule is followed that is based on time of day and Millerton Lake water elevation (FERC, 1993c).

Table 4.3-40 Minimum Releases Associated with Kerckhoff Asset

Facility	Time Period	Minimum Release (cfs)
Kerckhoff Reservoir**	Year Round	Normal Year:* 25 Dry Year: * 15

* A dry year is defined as any twelve-month period beginning May 1 in which the unimpaired runoff of the San Joaquin River at Millerton Lake for the April 1 to July 31 period, as forecast on April 1 by the State of California Department of Water Resources, and as may be adjusted by the State on May 1 or June 1, will be 45 percent or less of the average for such April-July period as computed by the State for the 50-year period used at the time. All other years are considered normal.

** Additional releases required May 15 through June 30, as follows. Release from the K2 powerhouse 775 cfs from 2200 to 0200 hours, and 400 cfs during the remaining hours, or 400 cfs from the K1 powerhouse, when the Friant Reservoir elevation is below 545 feet msl. When Friant Reservoir elevation is at or above 545 feet, 1,200 cfs from 2200 to 0200 hours and 775 cfs during the remaining hours, or 400 cfs from the K1 powerhouse.

Source: PG&E Co., 1999

FERC License Article 40 requires Pacific Gas and Electric Company to operate the system during flood periods in a manner that will not cause peak river flows below Kerckhoff Dam to exceed the peak flows that would have occurred in the absence of the facility (FERC, 1979d).

Water Quality. Beneficial uses associated with the San Joaquin River in the Kerckhoff reach are summarized in the 1994 Water Quality Control Plan for the Central Valley Region compiled by the Regional Water Quality Control Board, Central Valley Region (CRWQCB-CVR). The beneficial uses of the San Joaquin River from its sources to Millerton Lake, which includes the Kerckhoff reach, include:

- Municipal and Domestic Supply (MUN)
- Irrigation and Stock Watering (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)

The most recent license for the Kerckhoff facility was issued in 1979, so environmental studies, including water quality studies, of Kerckhoff Reservoir or this reach of the San Joaquin River have been limited. The only water quality information contained in Pacific Gas and Electric Company's Amended Application is water temperature data. However, Pacific Gas and Electric Company included a station on Kerckhoff Reservoir in its water quality studies for relicensing of the Crane Valley system. In addition, Southern California Edison (SCE) recently collected water quality data for the San Joaquin River immediately upstream of the Kerckhoff assets as part of their recent relicensing of their Big Creek No. 4 Project. Water quality conditions in Kerckhoff Reservoir can be expected to be similar to those in the San Joaquin River below the Big Creek No. 4 Powerhouse. Pertinent information from the studies associated with Pacific Gas and Electric Company's Crane Valley Facility and SCE's Big Creek No. 4 Project is summarized in the following table.

The water quality in Kerckhoff Reservoir and upstream in the San Joaquin River is excellent. All values of the water quality parameters measured, including parameters not included in the table above, met the Basin Plan standards. The reservoir temperatures during July 1977 never exceeded the 20°C standard for cold water habitat. Because of the small size of Kerckhoff Reservoir relative to inflow, the water column is not stratified with respect to temperature.

The San Joaquin River downstream of Kerckhoff Reservoir supports a cool to warm water fishery, and current operations ensure the maintenance of suitable water temperatures to support this beneficial use. Water temperature in the river is affected primarily by releases from upstream dams, tributary inflow, meteorological conditions, and minimum flows released from Kerckhoff Lake. The river temperature warms rapidly downstream from Kerckhoff Dam. During July 1976, maximum water temperatures in the lower part of the bypass reach exceeded 27°C, which is well above the upper lethal temperature for trout. Further discussion of water temperatures in this reach is presented in Section 4.4.

Table 4.3-41 Water Quality Parameters for Kerckhoff Reservoir and the San Joaquin River

Parameter	Kerckhoff Reservoir (PG&E)	San Joaquin River Upstream, 5/95 (SCE)	San Joaquin River Upstream, 9/94 (SCE)	Basin Plan Standard
Temperature (°C)	-	9.6	19.4	-
Dissolved Oxygen (mg/l) / Saturation (%)	9.3 – 11.6 / 94% - 104%	11.3	8.9	7.0
Turbidity (NTU)	1.3 – 2.2	2.2	0.38	-
Total Dissolved Solids (mg/l)	38 – 41	36	24	-
Total Suspended Solids (mg/l)	0.4 – 11.5	<0.5	<0.5	-
Conductivity (umhos/cm at 25°C)	23.0 – 50.0	29.3*	32.9*	-
pH	7.0 – 7.3	7.2	6.76	6.5 – 8.5
Alkalinity (as $CaCO_3$) (mg/l)	5.0 – 43.0			-
Hardness (as $CaCO_3$) (mg/l)	7.2 – 12.5	7.8	8.6	-
Cl (mg/l)	0.6 – 3.9	<1.8	1.8	-
Fe (mg/l)	0.065 – 0.19	0.134	0.082	0.3
Cu (mg/l)	<0.001 – 0.005	<0.001	<0.001	0.01
NH_4 (mg/l)	<0.01 – 0.03	<0.02	<0.02	-
NO_3 (mg/l)	0.03 – 0.09	<0.09	<0.09	10.0
PO_4 (mg/l)	0.01 – 0.05	-	-	-
Chlorophyll *a* (ug/l)	1.1 – 1.52	<5	-	
Fecal Coliform (MPN/100 ml)	<2 - 5	7	2	200

* Conductivity units = (uS/cm)

* For Kerckhoff reservoir during 1984 and 1985 and the San Joaquin river about a half mile upstream of the reservoir during September 1994 and May 1995

Sources: CVRWQCB, 1998 and SCE, 1995, and PG&E Co., 1986a

The minimum flow requirements for the Kerckhoff Facility are primarily designed to maintain adequate water temperature conditions and provide spawning flows for upmigrating American shad in the San Joaquin River between Kerckhoff Dam and Millerton Reservoir.

FERC License Article 19 requires Pacific Gas and Electric Company to take measures to prevent stream sedimentation and any form of water pollution. Large amounts of sediment have accumulated during storm flows near the intakes of the Kerckhoff powerhouses. Pacific Gas and Electric Company has proposed to remove these sediments by opening a low-level outlet in Kerckhoff Dam during periods of very high San Joaquin River flow (> 12,000 cfs). The high flows would dilute the sediments and flush them from the river channel below the dam. Resource agency staff have expressed concern that Pacific Gas and Electric Company's proposal does not adequately evaluate the potential presence of toxic materials in the sediments or potential adverse effects of sediment deposition on downstream flora, fauna and habitat.

Groundwater. Groundwater is not utilized by the Kerckhoff Hydroelectric Generating Facilities, thus groundwater information was not collected.

Bundle 18: Kings River

The Kings River Bundle consists of FERC No. 2735 (the Helms Pumped Storage Hydroelectric Generating Facility), FERC No. 1988 (the Haas and Kings River Hydroelectric Generating Facilities and associated appurtenances), and FERC No. 0175 (the Balch 1 and 2 Hydroelectric Generating Facilities and associated appurtenances). The three systems are located within the Kings River Basin, on the North Fork Kings River (NFKR) and the main stem of the Kings River within the Sierra National Forest. The NFKR joins the main stem Kings River just north of the Pine Flat Reservoir. Combined, the assets include four dams, which impound water in Courtright Reservoir, Wishon Reservoir, Black Rock Reservoir, and the Balch Afterbay. All of these reservoirs are located along the NFKR. These assets are being bundled together to maintain the FERC licenses No. 2735, 1988 and 0175, which share overlapping boundaries. In addition, these facilities also share existing water rights and are hydrologically linked, which will be maintained under this bundling.

Helms Pumped Storage (FERC 2735)

The Drainage Basin and Water Sources. The Helms Pumped Storage Facility lies within the North Fork Kings River (NFKR) basin, which drains the western slope of the Sierra Nevada, in Fresno County. The headwaters of the NFKR lie along the Sierra Nevada crest. All of the Helms Pumped Storage facilities are located on the NFKR and tributaries. The NFKR is part of the Tulare Lake Basin (PG&E Co., 1986d). The river flows in a southwesterly direction for approximately 40 miles before joining the mainstem Kings River. The drainage area within the NFKR basin that is utilized by the Helms Pumped Storage Facility is approximately 177 square miles, as measured from Lake Wishon (PG&E Co., 1986a).

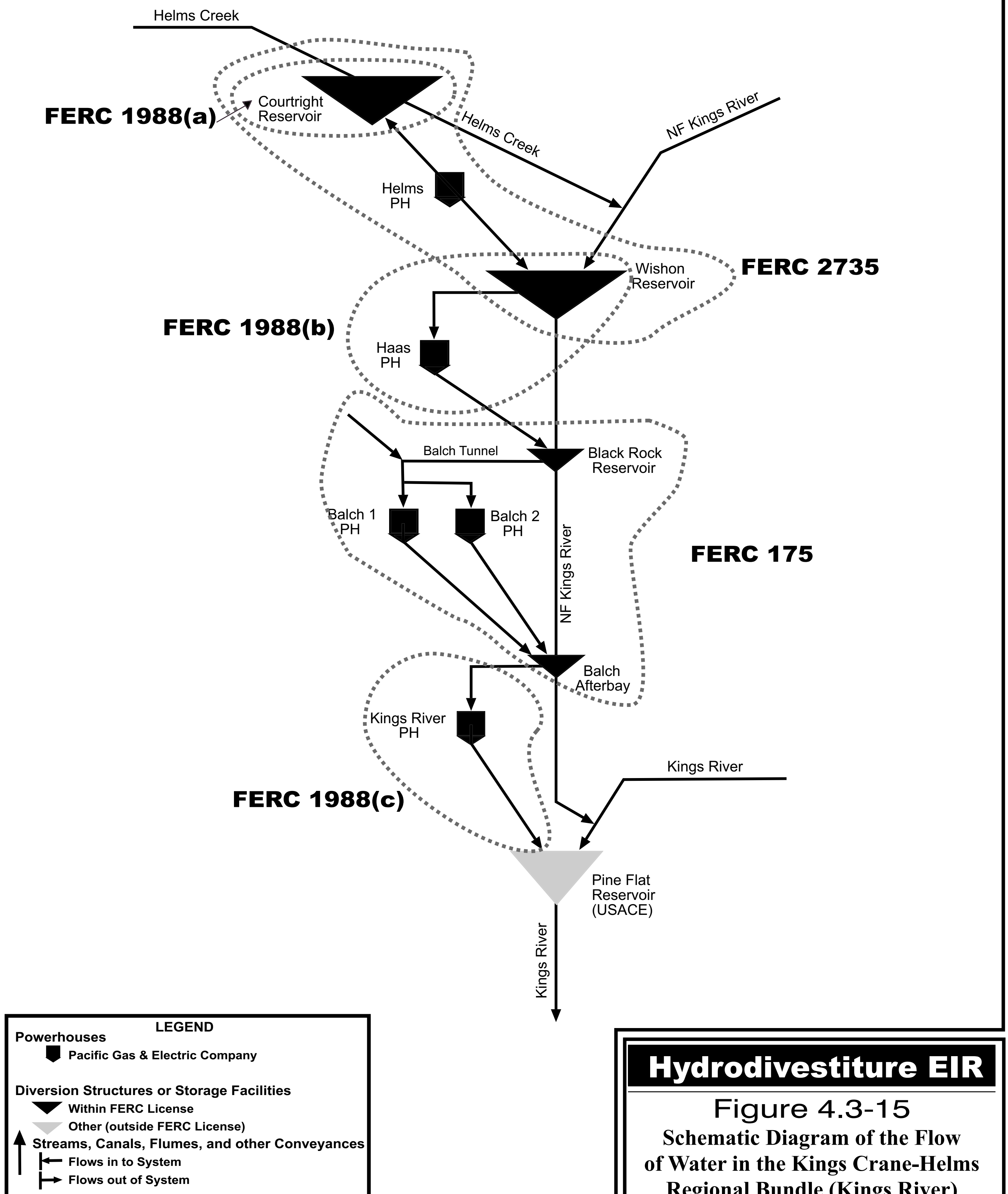
Hydroelectric Facilities. The Helms Pumped Storage Facility consists of the Helms Pumped Storage Hydroelectric Generating Facility. The facility includes a powerhouse, Wishon and Courtright Reservoirs (which are shared with the Haas-Kings River System), a tunnel, and associated appurtenant facilities (for example, conduits and penstocks), as shown in Figure 4.3-15.

Water Management. The NFKR originates near Blue Canyon Peak, at an elevation of 11,849 feet, in the John Muir Wilderness Area in Fresno County. The Helms Pumped Storage Facility is the uppermost power development on the river, utilizing the water stored in the two most upstream reservoirs, Courtright Lake and Lake Wishon, at elevations of 8,100 feet and 6,550 feet, respectively. Courtright Lake, the upper reservoir, lies on Helms Creek and has a usable storage capacity of 123,300 af. Lake Wishon, the lower reservoir, lies on the NFKR and has a usable storage capacity of 89,100 af for pumping purposes, and a total storage capacity of 129,078 af. The reservoirs are typically filled to capacity by June and are at their lowest in March. These two reservoirs provide the majority of the water storage capabilities for hydroelectric generation in the NFKR basin.

The surface elevation at the Helms Powerhouse (1,212.0 MW), located between Courtright Lake and Lake Wishon, is 6,330 feet (the powerhouse is approximately 1,000 feet below the surface). Courtright Lake and Lake Wishon are 2.65 miles upstream and 0.78 miles downstream of the powerhouse, respectively. The Helms Pumped Storage Facility circulates water between these two reservoirs, although the reservoirs also supply water to Pacific Gas and Electric Company’s downstream Haas-Kings River and Balch Systems. The facility is operated exclusively as a peaking unit, generating power when system energy demands are high, then pumping water back to Courtright Lake during off-peak hours. Normal maximum gross head at the facility is 1,744 feet (PG&E Co., 1998E).

In addition to power production, water is also released from Courtright Lake to supply instream habitat in Helms Creek. The FERC-required minimum release is four cfs from June through November and 2.5 cfs from December through May (FERC, 1983b). Mean annual flow in Helms Creek between 1985 and 1996 was 8.3 cfs. Helms Creek water merges with the NFKR and flows into Lake Wishon. Lake Wishon discharges a normal maximum of 825 cfs of water into the Haas Tunnel for generation at Haas Powerhouse (FERC No. 1988) and into the NFKR. Article 40 of the Haas-Kings River System FERC License (FERC No. 1988) requires a minimum flow to the NFKR of 15 cfs from June through November, and 7.5 cfs from December through May, although the flow may be reduced to 7.5 cfs year round during dry years (FPC, 1958). FERC License Article 44 requires Pacific Gas and Electric Company to maintain water levels as high as possible in Courtright Reservoir on weekends during the recreation season (FPC, 1976).

Water Quality. The beneficial uses associated with the NFKR are summarized in the 1995 Water Quality Control Plan for the Tulare Lake Basin compiled by the Regional Water Quality Control



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Hydrodivestiture EIR

Figure 4.3-15

Schematic Diagram of the Flow of Water in the Kings Crane-Helms Regional Bundle (Kings River)

Aspen Environmental Group

Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the NFKR include:

- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Rare, Threatened, or Endangered Species (RARE)
- Spawning, Reproduction, and/or Early Development (SPWN)
- Freshwater Replenishment (FRSH)

The quality of surface waters in the NFKR is generally excellent and water is typically clear, cold, and near saturation with respect to DO. Alkalinity is low and pH is near neutral. It is suspected that the Helms Pumped Storage Facility may increase the water temperature slightly in the downstream portions of the NFKR by recirculating water in Lake Wishon, preventing thermal stratification in the reservoir. The minimum flows released from downstream facilities were established to maintain acceptable water temperatures in the downstream reaches of the river. However, SWRCB staff note that water temperature standards for the protection of the COLD beneficial use that were in place when the existing licenses were issued, may not be considered acceptable to the certifying agency today or in future relicensing (SWRCB, 2000). Additional information about the water quality conditions at Wishon and Courtright Reservoirs, and the NFKR downstream of Wishon Reservoir is summarized below, under Haas-Kings Facilities.

It should be noted that the Helms Pumped Storage Facility includes a wastewater treatment plant that treats water for the Helms housing and support facilities. Wastewater is treated and then sprayed on land under a NPDES permit issued by the CVRWQCB. Pacific Gas and Electric Company received two Notices of Violation from the CRWQCB issued in December 1999 concerning discharges at the Helms Pumped Storage Facility and the Helms Housing and support facilities. According to Pacific Gas and Electric Company, these violations have been resolved. No future problems are expected.

Groundwater. There are no known major groundwater aquifers within the higher elevations of the study area, although seasonal groundwater of varying depth and continuity may be found. Groundwater in the watershed has not been extensively analyzed for this study because it is not utilized for power production at the Helms Pumped Storage Facility. However, any groundwater in the area is expected to be relatively soft and of high mineral content due to the carbonate rocks (Camp Dresser & McKee, 1997E).

Haas-Kings River (FERC 1988)

The Drainage Basin and Water Sources. The Haas-Kings River System lies within the NFKR basin, which drains the western slope of the Sierra Nevada, in Fresno County. The headwaters of the NFKR lie along the Sierra Nevada crest. All of the Haas-Kings River storage and diversion facilities are located on the NFKR and its tributaries. The NFKR is part of the Tulare Lake Basin (PG&E Co., 1986d). It flows in a southwesterly direction for approximately 40 miles before joining the mainstem of the Kings River. The drainage area within the NFKR basin that is utilized at the Haas Powerhouse is 177 square miles. The total drainage area used by the system is 246 square miles, as measured at the Kings River Powerhouse Forebay (PG&E Co., 1986a).

Hydroelectric Facilities. The asset consists of the Haas and Kings River hydroelectric generating facilities. Each facility has a powerhouse and associated appurtenant facilities (for example, conduits diversions, and penstocks), as shown in Figure 4.3-15. The Haas-Kings system also utilizes water stored in Wishon and Courtright Reservoirs, which are shared with the Helms Pumped Storage assets (FERC No. 2735).

Water Management. The Haas-Kings River System lies directly downstream of the Helms Pumped Storage Facility (FERC No. 2735), and utilizes the same reservoirs for storage and water management. In addition to the storage facilities Courtright Lake and Lake Wishon, the Haas-Kings River System utilizes the Balch Forebay (Black Rock Reservoir) and Balch Afterbay, both included in the Balch License (FERC No. 175). From a power generation standpoint, all facilities on the NFKR from Courtright Lake to Pine Flat Reservoir (which is operated by the USACE on the mainstem Kings River) are interconnected by a series of reservoirs and conduits, and must be operated in coordination with each other. The size of the reservoirs allows peaking operations to take place through most of the year, although the powerhouses may be baseloaded during high runoff periods. The two powerhouses of the Haas-Kings River System are separated by the Balch System (FERC No. 0175).

Water released from Lake Wishon flows through the 6.19-mile-long Haas Tunnel to the Haas Powerhouse (144 MW). The normal maximum flow through Haas Powerhouse is 825 cfs, and the normal maximum gross head is 2,444 feet (PG&E Co., 1998E). The Haas Powerhouse tailrace water flows directly into Black Rock Reservoir, where it is diverted through the 3.6 mile-long Balch Tunnel to Balch 1 and 2 Powerhouses (139 MW), all part of the Balch System (FERC No. 0175). After flowing through the Balch Powerhouses, the water enters Balch Afterbay. From the Balch Afterbay, water is diverted into the 3.9-mile-long Kings River Tunnel to the Kings River Powerhouse (52 MW). The normal maximum flow through the powerhouse is 990 cfs, and the normal maximum gross head is 798 feet (PG&E Co., 1998E). The powerhouse discharges the water into the upstream end of Pine Flat Reservoir. Both Haas and Kings River Powerhouses are typically operated as peaking facilities, in coordination with peaking operations at the Balch powerhouses.

FERC License Article 40 requires a release from Lake Wishon into the NFKR of 15 cfs from June through November and 7.5 cfs from December through May. During dry years the release may be set at 7.5 cfs year around. This article also requires a release from the Balch Afterbay into the NFKR of 15 cfs from June through November and ten cfs from December through May (FERC,

Table 4.3-42 Minimum Releases Associated with Haas-Kings River Assets

Facility	Time Period	Minimum Release (cfs)
Courtright Reservoir	June through November	4
	December through May	2.5
Wishon Reservoir	June through November	Normal Year:* 15
		Dry Year:* 7.5
	December through May	7.5
Balch Afterbay	June through November	Normal Year: ** 15
		Dry Year: ** 10
	December through May	10
Dinkey Creek Siphon	Year Round	5***
North Fork Kings River below confluence with Dinkey Creek	June through November	Normal Year: * 35
		Dry Year: * 25
	December through May	25

* A dry year is defined as any 12-month period beginning May 1 in which the total unimpaired seasonal runoff of the Kings River at Pine Flat Reservoir for the October 1 to September 30 water year period, as forecast on April 1 by the California Department of Water Resources (DWR), and as may be adjusted by DWR on May 1, will be 1,000,000 acre-feet or less.
** A dry year is defined as any 12-month period beginning May 1 in which natural run-off of the Kings River at Pine Flat Reservoir for the April 1 to July 31 period as forecast on April 1 by the State of California Department of Water Resources, and as may be adjusted by the State on May 1, will be 50 percent or less of the average for such period as computed by the State for the 50-year period used at that time.
*** Required if natural flow of Dinkey Creek is 60 cfs or less.
Source: PG&E Co., 1999

1956). During dry years the release may be set at ten cfs year round. Periodic spills from the afterbay have elevated flows in the NFKR above these release values, resulting in a mean annual flow of 86.5 cfs for the period 1960-1996.

Additional water releases are made by Pacific Gas and Electric Company from the Kings River Dinkey Creek Siphon. FERC License Article 40 requires that when natural flows in Dinkey Creek drop to 60 cfs or less, five cfs must be released from the Dinkey Creek Siphon. Total flows in the NFKR below its confluence with Dinkey Creek must be maintained at 35 cfs from June through November, and at 25 cfs from December through May, although flows of 25 cfs are allowed year-round during dry years.

The Haas-Kings River System is currently undergoing FERC relicensing. These minimum flows are currently under review and may be modified when FERC issues a new license.

FERC License Article 32 requires Pacific Gas and Electric Company to operate and maintain the system so as to not increase the rate or volume of inflow into Pine Flat Reservoir over that which would occur under natural conditions during periods when the reservoir's storage capacity reserved for flood control is being used. Additionally, Pacific Gas and Electric Company, USACE, and the

California Department of Water Resources have a written agreement to share reservoir operation plans at the Pine Flat Reservoir during times of critical flood control operation (FERC, 1999b).

FERC License Article 36 requires Pacific Gas and Electric Company to maintain the water surfaces of the system reservoirs as high as possible and with minimum fluctuation during the major recreation season (June 15 through September 15) (FPC, 1955), and FERC License Article 46 requires Pacific Gas and Electric Company to keep Courtright Reservoir water levels as high as possible on weekends during the recreation season (FPC, 1956). In compliance with FERC License Article 41, Pacific Gas and Electric Company operates the system to avoid sudden releases of large flows downstream (FPC, 1956).

Water Delivery and Domestic Use. Pacific Gas and Electric Company has water rights in the Haas-Kings River System. There are additional contracts for water delivery or supply.

Water Quality. Beneficial uses associated with the NFKR are summarized in the 1995 Water Quality Control Plan for the Tulare Lake Basin compiled by the Regional Water Quality Control Board, Central Valley Region (CRWQCB-CVR). The beneficial uses of the NFKR include:

- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Rare, Threatened, or Endangered Species (RARE)
- Spawning, Reproduction, and/or Early Development (SPWN)
- Freshwater Replenishment (FRSH)

Beneficial uses associated with the main stem of the Kings River immediately below the Kings River Powerhouse (to Pine Flat Reservoir) are similar except that they do not include RARE or SPWN.

The Haas-Kings River assets have been undergoing relicensing and a new license is eminent. As part of the relicensing process, FERC prepared an Environmental Assessment (FERC 1996) which documents, among other things, water quality conditions along the entire NFKR, including water quality conditions at Wishon, Courtright, Black Rock, and Balch Afterbay Reservoirs, and in the NFKR from Wishon Reservoir to the Haas-Kings Powerhouse. The information contained in this document is pertinent to all of the assets in the Kings River Bundle, and is therefore summarized in the following, along with information contained in Pacific Gas and Electric Company's PEA.

Between the years 1972 and 1984, Pacific Gas and Electric Company analyzed the water quality at six locations including: 1) Courtright Reservoir; 2) Wishon Reservoir; 3) NFKR and tributaries from Lake Wishon to Black Rock Reservoir; 4) Black Rock Reservoir; 5) NFKR below Black Rock Reservoir; and 6) Kings River to the Kings River powerhouse. Parameters assessed included dissolved oxygen (DO) pH, turbidity, specific conductance, nutrients, suspended solids, total alkalinity, ions, fecal coliform, oil and grease, and boron. Other than a few isolated instances, the U.S. Environmental Protection Agency (EPA) and CVRWQCB standards were met. The results indicate that Courtright and Wishon Reservoirs have excellent water quality. The rest of the area generally has very good quality water and typically meets EPA and CVRWQCB goals. The water is generally clear, cold, and near saturation with DO. Alkalinity is low and pH is near neutral.

High fecal coliform levels were occasionally recorded during low flow periods in the tributaries of the NFKR, especially Long Meadow Creek. These occurrences were attributed to livestock, logging activities, wildlife and recreation. Increased turbidities periodically occurred in various NFKR tributaries following periods of rainfall or snowmelt. Courtright Lake and Lake Wishon exhibit specific conductance, pH, and alkalinity that, while not always meeting EPA and/or CVRWQCB criteria, represented acceptable levels for high elevation, oligotrophic water bodies. DO levels of frequently did not meet CVRWQCB criteria of 9 milligrams per liter (mg/L). However, EPA standards were almost always met and levels throughout the facility area were within a few percent of saturation.

The most substantial water quality issue relates to water temperature occur in the facility bypass reaches and tailraces. Water temperature in the river is affected by the storage reservoirs, tributary inflow, the operation of the Helms Pumped Storage Facility, meteorological conditions, and minimum flow releases. The degree to which facility operations (controllable factors) result in increased water temperatures is not known. Water temperatures are warmer in the lower sections of the NFKR and in the mainstem Kings River, often exceeding 20°C in the summer. The Haas-Kings River System supports both warm and cold water fisheries at different locations. Water temperature conditions in the NFKR and Pacific Gas and Electric Company reservoirs are discussed in more detail in Section 4.4.

Groundwater. There are no known major groundwater aquifers within the higher elevations of the study area, although seasonal groundwater of varying depth and continuity may be found. Groundwater in the watershed has not been analyzed for this study, because it is not utilized by the Haas-Kings River System. However, any groundwater in the area is expected to be relatively soft and of high quality. If originating from carbonate rocks, the groundwater would exhibit a high mineral content (Camp Dresser & McKee, 1997F) (PG&E Co., 1986d).

Balch (FERC 175)

The Drainage Basin and Water Sources. The Balch System lies within the NFKR drainage basin, which drains the western slope of the Sierra Nevada, in Fresno County. All of the Balch storage and diversion facilities are located on the NFKR and its tributaries. The NFKR is part of the larger Tulare Lake Basin. The river flows in a southwesterly direction for approximately 40 miles before joining with the mainstem Kings River (PG&E Co., 1986d). The drainage area that is utilized by the Balch System within the NFKR watershed is 223 square miles, as measured from Balch 1 Powerhouse, and 233 square miles from Balch 2 Powerhouse Forebay (PG&E Co., 1986a).

Hydroelectric Facilities. The asset consists of the Balch 1 and Balch 2 powerhouses, Black Rock Reservoir, and the Balch Afterbay. The Balch powerhouses are situated along the NFKR between the Helms Pumped Storage Facilities and the Haas-Kings River Facilities. Each facility has a powerhouse, diversion, and associated appurtenant facilities (for example, conduits and penstocks). The two powerhouses share Black Rock Reservoir as a forebay and the Balch Afterbay as shown in Figure 4.3-15.

Water Management. The facilities are hydrologically linked with those of the Haas-Kings River System (FERC No. 1988). The Balch facilities are located between the Haas Powerhouse and the Kings River Powerhouse, receiving water from the Black Rock Reservoir and discharging it into the Balch Afterbay. Black Rock Reservoir is approximately seven miles downstream of Wishon Reservoir. Located at an elevation of 4,089 feet, it has 1,260 af of usable storage. The reservoir receives tailrace water from Haas Powerhouse and water released from Lake Wishon, as well as tributary inflow downstream of Lake Wishon. Major tributaries between Wishon and Black Rock Reservoirs include Long Meadow, Teakettle, and Rancheria Creeks. From Black Rock Reservoir, water enters an approximately 3.6-mile-long conduit to both powerhouses. The maximum flow through Balch 1 and 2 Powerhouses is 843 cfs. The flow in Balch Tunnel is supplemented by water that is diverted from Black Rock Creek and Weir Creek into pipes that transport it to the Balch Tunnel. Ordinarily, 990 cfs of water is discharged into Balch Afterbay and diverted into the Kings River Tunnel for downstream use at Kings River Powerhouse. The Balch 1 Powerhouse has a normal maximum gross head of 2,379 feet, and the Balch 2 Powerhouse has 2,389 feet (PG&E Co., 1998E).

FERC License Article 38 requires minimum releases into the NFKR from Black Rock Reservoir (FERC, 1983c). A minimum flow of 5 cfs must be released from June 1 through November 30, and 2.5 cfs must be released the remainder of the year. During dry years, 2.5 cfs must be released all year. Periodic spills from the reservoir have elevated flows in the NFKR above these release values, resulting in a mean annual flow of 66.7 cfs for the period 1984-1996. The Balch Powerhouses are operated as either peaking or baseload facilities depending on water availability.

FERC License Article 45 requires Pacific Gas and Electric Company to operate the facility during flood periods to ensure that the peak river flow below Balch Afterbay does not exceed that which would have occurred in the absence of the facility (FERC, 1980c).

Water Delivery and Domestic Use. Pacific Gas and Electric Company has water rights in the Balch System. There are additional contracts for water delivery or supply.

Table 4.3-43 Minimum Releases Associated with Balch Facility

Facility	Time Period	Minimum Release (cfs)
Black Rock Reservoir	June through November	Normal Year: * 5
		Dry Year: * 2.5
	December through May	2.5

* A dry year is any twelve-month period beginning May 1 in which natural run-off of the Kings River at Pine Flat Reservoir for the April 1 to July 31 period as forecast on April 1 by the State of California Department of Water Resources, and as may be adjusted by the State on May 1, will be 50 percent or less of the average for such period as computed by the State for the 50-year period used at that time.

Source: PG&E Co., 1999

Water Quality. The beneficial uses associated with the NFKR are summarized in the 1995 Water Quality Control Plan for the Tulare Lake Basin compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial include:

- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Rare, Threatened, or Endangered Species (RARE)
- Spawning, Reproduction, and/or Early Development (SPWN)
- Freshwater Replenishment (FRSH)

The existing water quality in the NFKR is generally excellent and water is typically clear, cold, and near saturation with respect to DO. Alkalinity is low and pH is near neutral. Water temperatures are warmer in the lower sections of the NFKR, often exceeding 20°C in the summer. Portions of the NFKR support a cold water fishery. Current operations target the maintenance of cold water temperatures to support this beneficial use. Water temperature in the river is affected by the storage reservoirs, tributary inflow, meteorological conditions, and minimum flow releases.

The minimum flow releases required in FERC License Article 38 are designed in part to maintain water temperatures at levels that are beneficial to the aquatic environment, particularly the release from the Dinkey Creek Siphon.

Deposition of sediment has been a water quality issue in the Balch bypass reach. Sediments, primarily sand, have deposited in this segment of the NFKR when the Balch Afterbay is drained to maintain certain facilities. Pacific Gas and Electric Company is bound by an order from the CVRWQCB to maintain turbidity in the NFKR at levels between 0 and 200 Jackson Turbidity Units (JTU) depending upon the time of year.

Groundwater. There are no known major groundwater aquifers within the higher elevations of the study area, although seasonal groundwater of varying depth and continuity may be found. Groundwater in the watershed has not been analyzed for this study, because it is not utilized by the

Balch System. However, any groundwater in the area is expected to be relatively soft and of high mineral content due to the carbonate rocks (Camp Dresser & McKee, 1997F) (PG&E Co., 1986D).

Bundle 19: Tule River

Tule River (FERC 1333)

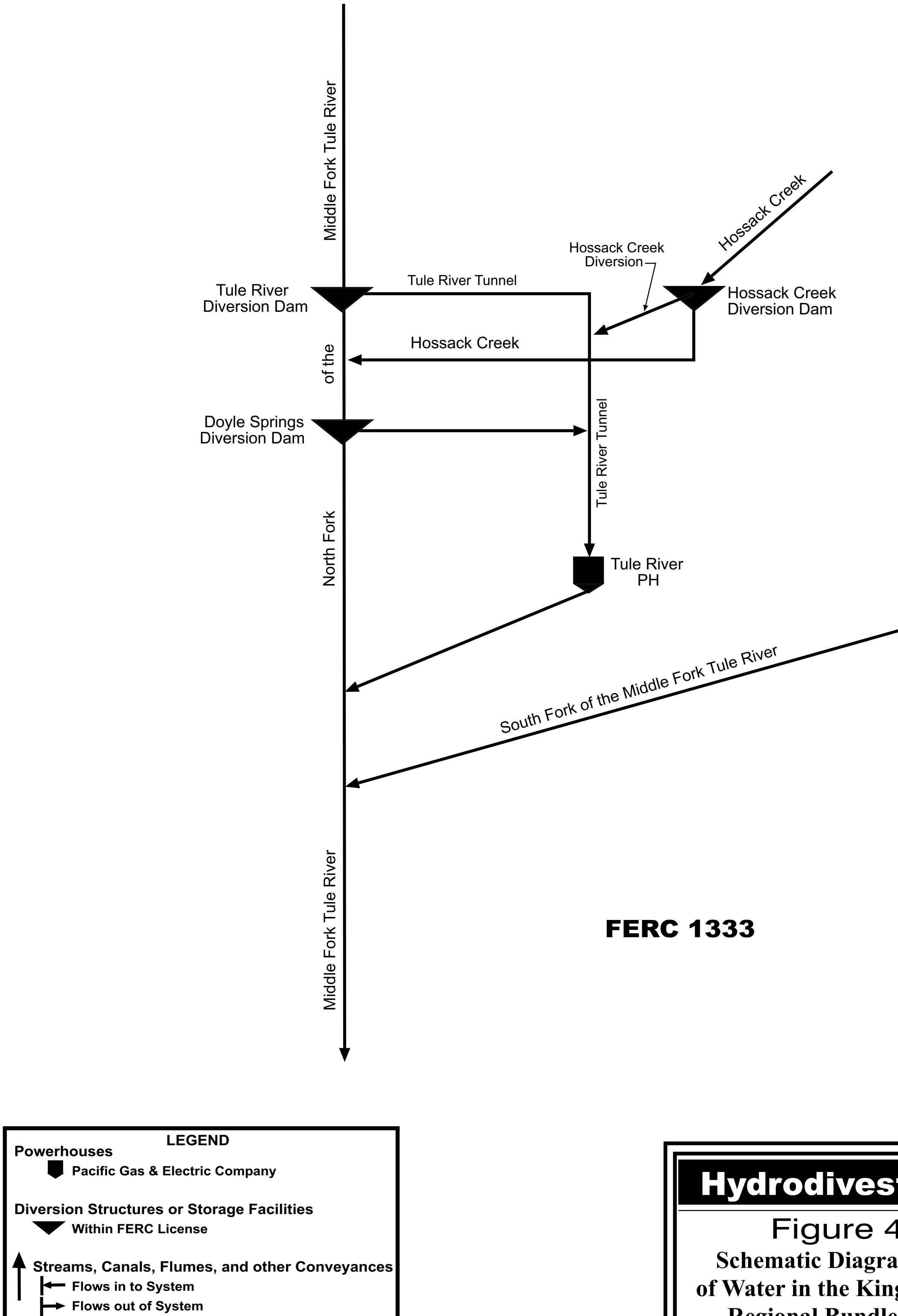
The Tule River Bundle consists of FERC No. 1333 (the Tule River Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

The Drainage Basin and Water Sources. The Tule River System lies within the North Fork of the Middle Fork Tule River (NFMFTR) drainage basin, which drains the western slope of the Sierra Nevada in Tulare County. The headwaters of the basin originate in Sequoia National Park at an elevation of approximately 9,600 feet. The NFMFTR flows southwesterly for about 13.5 miles from the headwaters to the confluence with the Middle Fork Tule River at 2,400 feet. All of the Tule River diversion facilities are located on the NFMFTR and its associated tributaries. The contributing drainage area for the Tule River System is 34.1 square miles, as determined directly downstream of Doyle Springs Diversion Dam (PG&E Co., 1986a).

Hydroelectric Facilities. All of the Tule River facilities are located on the NFMFTR and its associated tributaries. The asset diverts water from the NFMFTR at a small diversion dam located about three miles upstream of the Tule River Powerhouse. It also diverts water from a small tributary, referred to as Hossack Creek and from a spring referred to as Doyle Springs. Water diverted at these three sources is conveyed through a system of the ditch, tunnel and pipe to the Tule Powerhouse, which is located at the confluence of the North and Middle Forks of the Tule River. There are no storage reservoirs associated with the Tule River Hydroelectric Generating Facility, and none are located upstream. Figure 4.3-16 shows the key facilities associated with this asset.

Water Management. The Tule River System contains no storage or regulating reservoirs, and no reservoirs are located upstream of the system. Therefore, natural river flow and seasonal snow melt runoff provide the only regulation of water (PG&E Co., 1997B). There are three diversion dams associated with the system: Tule River, Hossack Creek, and Doyle Springs at elevations of 4,010 feet, 4,020 feet, and 3,815 feet, respectively.

The Tule River Diversion Dam is on the NFMFTR and diverts water into the Tule River Conduit. The Hossack Creek Diversion dam is located on, and diverts water from, Hossack Creek to the Tule River Conduit through a 106-foot-long pipe. The Doyle Springs Diversion Dam impounds less than 1 acre foot of water from below the Tule River Diversion Dam and flow from Doyle Springs. An electric pump conveys the water through a 1,250-foot-long pipe to the Tule River Conduit. The Tule River Conduit has a maximum capacity of 66 cfs. Water is conveyed down the 3.2 mile-long Tule River Conduit to a 1,240-foot wood stave pipe, and then down a 3,600 foot penstock to the



Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

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Figure 4.3-16

Schematic Diagram of the Flow of Water in the Kings Crane-Helms Regional Bundle (Tule River)

Aspen *Environmental Group*

Table 4.3-44 Minimum Releases Associated with Tule River Assets

Facility	Time Period	Minimum Release (cfs)
Tule River Diversion Dam	May 15 through September 15	Normal Year: * 7
		Dry Year: * 4
	September 16 through May 14	4
Doyle Springs	Year Round	2

* A dry year is any 12-month period beginning May 1 in which the inflow to Lake Success for the water year, as forecast on April 1 by the State of California Department of Water Resources (DWR), and as may be adjusted by the State on May 1 or June 1, will be 50 percent or less of the average for such water year, as computed by the State for the 50-year period used at that time. If, during a designated dry year, the February 1 or March 1 DWR forecast indicates that dry.

Source: PG&E Co., 1999

Tule River Powerhouse (6.4 MW). Normal maximum gross head at the powerhouse is 1,544 feet (PG&E Co., 1998E).

FERC License Articles 105 and 401 require that a minimum flow of seven cfs (or natural stream flow, whichever is less) must remain in the river below Tule River Diversion Dam from May 15 through September 15 (FERC, 1993c). A minimum of four cfs must remain in the river the remainder of the year. During dry years, four cfs, or natural stream flow, whichever is less, must remain in the river all year. Below the Doyle Springs Diversion Dam, the minimum instream requirement is two cfs all year. FERC License Article 405 requires ramping rates below both diversion dams; release flows below the diversions must not be reduced by more than 50 percent an hour (FERC, 1994d).

The Tule River System operates as an ROR facility, since it relies on water in excess of the minimum instream flows required for habitat purposes. ROR facilities limit the ability of the operator to engage in certain generation strategies such as peaking and provision of some incidental services.

Water Quality. The State Water Resources Control Board (SWRCB) has classified the various segments of the Tule River according to the particular beneficial uses occurring in that segment. These segments and associated beneficial uses are summarized in the 1995 Water Quality Control Plan for the Tulare Lake Basin (Basin Plan) compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses of the Tule River, upstream of Lake Success are as follows:

- Municipal and Domestic Water Supply (MUN)
- Agriculture Supply (AGR)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Cold Freshwater Habitat(COLD)
- Wildlife Habitat (WILD)
- Rare, Threatened, or Endangered Species (RARE)

Table 4.3-45 Tule River Water Quality Data

Parameter	Tule River Diversion Dam		Below Doyle Springs	Powerhouse		Basin Plan Standard
	Above	Below		Below	Above	
pH, field	7.80	7.55	7.36	7.84	8.13	6.5-8.3 (or changed by 0.3 units)
pH, laboratory	7.90	8.11	7.58	8.27	8.25	
Hardness (as CaCO3)	40.1	39.5	316	71.5	126	-
Total dissolved solids (mg/L)	79	76	383	150	217	-
Calcium (mg/L)	12.4	12.1	107	22.3	37.7	-
Bicarbonate (mg/L)	82.4	85.4	437	128	212	-
Total alkalinity (as mg/L CaCO3)	67.5	70.0	358	105	174	-
Electrical conductivity (umhos/cm)	170	140	570	200	350	450
Dissolved oxygen (mg/L and % saturation)	9.04 84%	8.96 83%	8.50 85%	9.0 86%	8.66 90%	7.0

Source: CVRWQCB, 1995

- Spawning, Reproduction, and/or Early Development (SPWN)
- Freshwater Replenishment (FRSH)

The Tule River Facility was recently relicensed. As part of the relicensing process the FERC prepared an Environmental Assessment that documents, among other things, water quality conditions in the Tule River reach. The information contained in the FERC's EA is based on studies conducted by Pacific Gas and Electric Company. Water quality measurements taken by Pacific Gas and Electric Company are summarized in the following table.

As indicated, the water quality in this area is generally good; however, below Doyle Springs the water quality is characterized by increased levels of hardness, total dissolved solids, calcium, bicarbonate, total alkalinity, and electrical conductivity compared to other segments of the stream. pH levels throughout the bundle were within those outlined in the Basin Plan. However, the pH levels increased from upstream to downstream by more than 0.3 units, suggesting that the facility waters do not comply with the Basin Plan standard for pH. Dissolved oxygen levels met or exceeded the Basin Plan standard at all sites. Electrical conductivity met the Basin Plan standard at all sites except the site immediately below Doyle Springs.

The high pH, carbonate and conductivity levels are naturally elevated near Doyle Springs and deposits of travertine (calcium carbonate) are present along the stream bed and the bank between Doyle Springs and the Tule River. According to the FERC, precipitation of calcium carbonate may be exacerbated by reductions in flow. Regardless, the FERC does not believe it would be practical to increase flows to the extent that the precipitation and deposition of calcium carbonate could be ameliorated.

The lower portions of the reach, below Doyle Springs Diversion Dam, are also characterized by elevated water temperatures, particularly during the summer months. Pacific Gas and Electric Company studies indicate water temperature generally increases from the Tule River Diversion Dam to the powerhouse. Accordingly, the FERC license issued in 1993 included minimum instream flow requirements designed to moderate water temperature downstream of Doyle Springs. However, SWRCB staff note that water temperature standards for the protection of the COLD beneficial use that were in place when the existing license was issued, may not be considered acceptable to the certifying agency today or in future relicensing (SWRCB, 2000). Additional information about water temperature is provided in Section 4.4.

Groundwater. No information was collected about groundwater in the Tule River basin because the Hydroelectric Generating Facility does not use groundwater.

Bundle 20: Kern Canyon

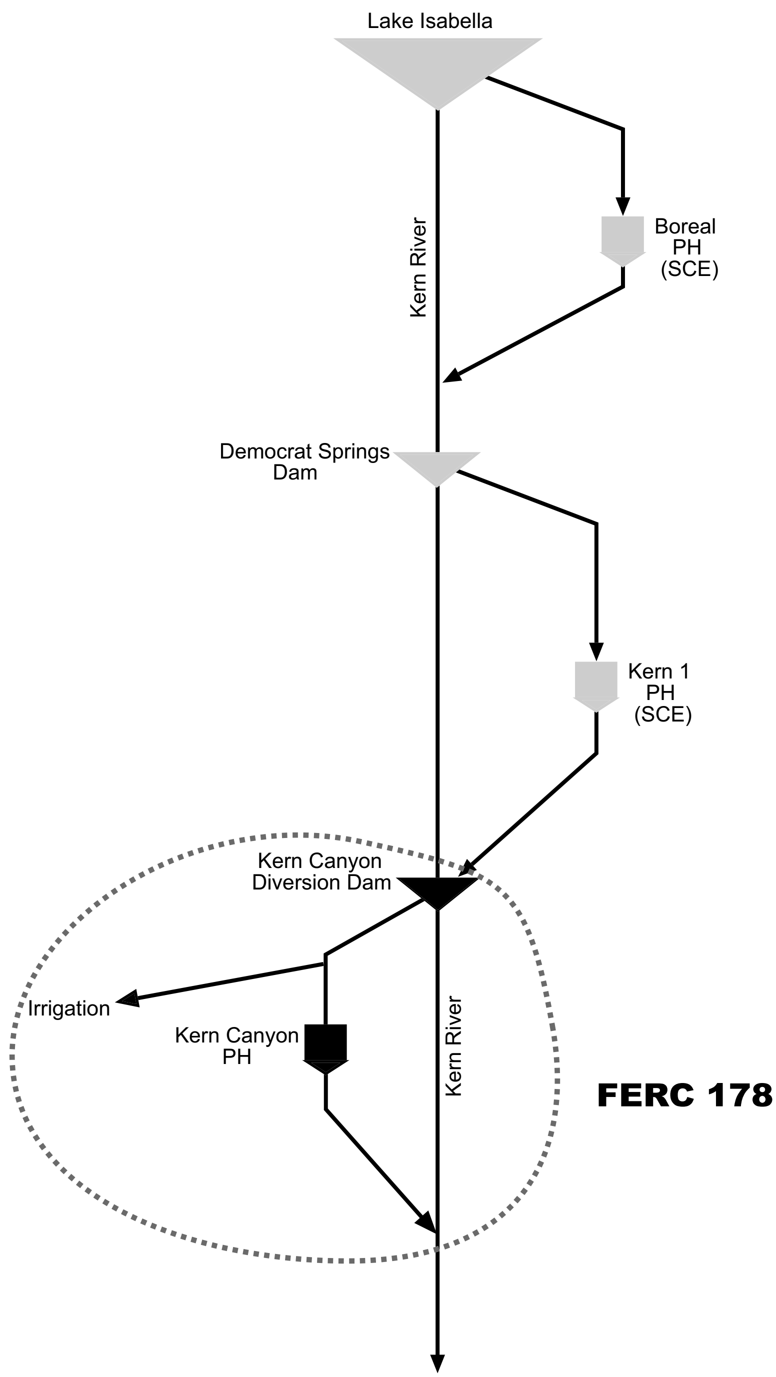
Kern Canyon (FERC 178)

The Kern Canyon Bundle consists of FERC No. 178 (the Kern Canyon Hydroelectric Generating Facility and associated appurtenances). This asset is a single generating facility.

The Drainage Basin and Water Sources. The Kern Canyon Facility lies within the Kern River Basin, which drains the western slope of the Sierra Nevada, in Kern County. The headwaters of the Kern River lie near Mt. Whitney, the highest peak in the contiguous United States. From its headwaters, the Kern River flows southerly then southwesterly for nearly 100 miles in the mountains before emerging in the San Joaquin Valley near Bakersfield. All of the Kern Canyon diversion and storage facilities are located on the Kern River. The drainage area within the Kern River Basin that is utilized by the Kern Canyon Facility is approximately 2,310 square miles (PG&E Co., 1986a).

Hydroelectric Facilities. The Kern Canyon Hydroelectric Generating Facility is located along the Kern River. The facility diverts up to 650 cfs of water from the Kern River at a small diversion dam located about 1.6 miles upstream of the Kern Canyon Powerhouse. Water is conveyed through a tunnel to a small powerhouse and forebay and then through the Kern Canyon Powerhouse. The powerhouse and associated appurtenant facilities (for example, conduits and penstocks), are shown in Figure 4.3-17. Water is discharged from the powerhouse into the Kern River, where it is almost immediately diverted again by the Olcese Water District for use in the Rio Bravo Hydroelectric Project. There are no storage reservoirs associated with the Kern Canyon Facility.

Water Management. Three reservoirs provide storage, regulation, and diversion functions on the Kern River upstream of the facility. These reservoirs include Lake Isabella, Democrat Springs Dam, and Kern River 1 Powerhouse Afterbay (PG&E Co., 1997B). Lake Isabella, operated by the USCAE, is approximately 32 miles upstream of the Kern Canyon Facility, at an elevation of 2,605



LEGEND

Powerhouses
- Pacific Gas & Electric Company
- Other (outside FERC License)

Diversion Structures or Storage Facilities
- Within FERC License
- Other (outside FERC License)

Streams, Canals, Flumes, and other Conveyances
- Flows in to System
- Flows out of System

Source: "Pacific Gas & Electric Company's PEA (Proponent's Environmental Assessment) Errata, June 8, 2000, Revision Errata Attachment 2, modified by Aspen Environmental Group, 2000.

Hydrodivestiture EIR

Figure 4.3-17

Schematic Diagram of the Flow of Water in the Kings Crane-Helms Regional Bundle (Kern River)

Aspen Environmental Group

feet (PG&E Co., 1972B). Lake Isabella has an active storage capacity of about 570,000 af and is primarily operated to provide irrigation water to the San Joaquin Valley (PG&E Co., 1997B) (PG&E Co., 1972B). The other two reservoirs, Democrat Springs Reservoir, and the Kern River 1 Powerhouse Afterbay, are part of systems operated by the Southern California Edison Company (SCE). The Kern Canyon reservoir has a storage capacity of 27 af at a maximum water surface elevation of 948 feet (PG&E Co., 1984).

Kern Canyon Reservoir, created by the Kern Canyon Diversion Dam, serves as the forebay for the Kern Canyon Facility. A maximum of 750 cfs can be diverted from this reservoir through a 1.6-mile-long conduit to the penstock and powerhouse. The water that is used for power generation at the Kern Canyon Powerhouse (11.5 MW) is discharged back into the Kern River. Operations of the Kern Canyon Powerhouse are coordinated with the SCE facilities. Normal maximum gross head at the powerhouse is 264 feet (PG&E Co., 1998E).

Flows in excess of the conduit capacity commonly occur in the summer months, resulting in spills into the Kern River. FERC License Article 34 requires Pacific Gas and Electric Company to release a variable minimum flow from the diversion dam, based on water year type (FERC, 1997d). Pacific Gas and Electric Company must provide a minimum release of 25 cfs to the river during normal water years and 12.5 cfs during dry years as measured at the streamflow gaging station, KE-16, located 350 feet downstream of the Kern Canyon Diversion Dam.

Table 4.3-46 Minimum Releases Associated with Kern Canyon Facility

Facility	Time Period	Minimum Release (cfs)
Kern Canyon Diversion Dam	Year Round	Normal Year: * 25 Dry Year: * 12.5

* A dry year is any 12-month period, beginning May 1, in which the inflow to Lake Isabella for the water year, as forecast on April 1 by the State of California Department of Water Resources, and as my be adjusted by the State on May 1 or June 1, will be 50 percent or less of the average for such water year, as computed by the State for the 50-year period used at the time.

Source: PG&E Co., 1999

Since the facility has no storage reservoir and its operations are entirely dependent on upstream releases, it is operated as an ROR facility. ROR facilities limit the ability of the operator to engage in certain generation strategies such as peaking and provision of some incidental services.

Water use is also governed by a water conveyance contract between Pacific Gas and Electric Company and La Hacienda, Inc., whereby Pacific Gas and Electric Company conveys La Hacienda water through the Kern Canyon tunnel according to a schedule submitted by La Hacienda (PG&E Co., 1982b). This contract constrains the operation of the facility under current conditions.

Water Delivery and Domestic Use. Pacific Gas and Electric Company has water rights in the Kern Canyon System. There are additional contracts for water delivery or supply.

Water Quality. The State Water Resources Control Board (SWRCB) has classified the various segments of the Kern River according to the particular beneficial uses occurring in that segment. These segments and associated beneficial uses are summarized in the 1995 Water Quality Control Plan for the Tulare Lake Basin (Basin Plan) compiled by the Regional Water Quality Control Board, Central Valley Region. These beneficial uses serve as a basis for establishing water quality standards. Beneficial uses for the segment of the Kern River below the Kern Canyon Diversion Dam are identified as follows:

- Municipal and Domestic Water Supply (MUN)
- Agriculture Supply (AGR)
- Industrial Service Supply (IND)
- Industrial Process Supply (PRO)
- Hydropower Generation (POW)
- Water Contact Recreation (REC-1)
- Non-Contact Water Recreation (REC-2)
- Warm Freshwater Habitat (WARM)
- Wildlife Habitat (WILD)
- Rare, Threatened, or Endangered Species (RARE)
- Ground Water Recharge (GWR)

Importantly, the beneficial uses do not include Cold Freshwater Habitat (COLD), Spawning, Reproduction, and/or Early Development Fish Habitat (SPWN), or Freshwater Replenishment (FRSH).

The Kern Canyon Facility is currently undergoing relicensing. Pacific Gas and Electric Company recently issued a Notice of Preparation (NOP) but no other documents are currently available. As such, very little information exists regarding water quality conditions in the Kern Canyon Facility Reach. According to Pacific Gas and Electric Company's PEA the surface water quality of the Kern River is generally good. The river has been found to be high in phosphates and calcium carbonate. The nutrient load of the river, possibly stimulated by undesirable water temperature, results in a high production of algae. A minimum flow requirement is in place to help control water temperature in the Kern River to support a warm water fishery. FERC license Article 19 requires Pacific Gas and Electric Company to take measures to prevent stream sedimentation and any other form of water pollution.

Southern California Edison recently relicensed their KR-1 Project, which lies immediately upstream of Pacific Gas and Electric Company's Kern Canyon Facility. SCE conducted water quality studies in association with the relicensing of the KR-1 Project. The results of these studies are documented in their Application for New License and in the FERC's Environmental Assessment (EA) dated March 19, 1998. Water quality conditions in the Kern Canyon Facility reach can be expected to be similar to those immediately upstream in the KR-1 Project Reach. Therefore, pertinent information from these two documents is summarized in the following.

SCE analyzed water quality samples collected upstream of Democrat dam, within the bypassed reach, and downstream of the powerhouse on March 31 and September 23, 1992. The study results found facility water characteristic of the Kern River basin: calcium sodium bicarbonate water, soft, relatively low in dissolved solids, and slightly alkaline. Ammonia and pH did not meet water quality objectives defined by the CRWQCB or SWRCB at a few sample sites. The high pH readings appear to be associated with the relatively high natural alkalinity which is characteristic of the Kern River. High ammonia readings appear to be associated with livestock grazing and/or septic tank discharges. Dissolved oxygen concentrations exceeded basin plan standards upstream of SCE's diversion dam but were below basin plan standards at a location downstream of SCE's powerhouse, in the Kern Canyon Facility Reach. Water temperature was not considered a problem by the FERC but the SWRCB conditioned SCE's new license with a requirement to conduct a five year monitoring study to determine whether facility flows affect water temperatures to the extent that trout habitat is adversely affected. In any case, water temperature should not be a concern in the Kern Canyon Facility reach because it is not designated as a COLD water river segment.

Groundwater. No information was collected about groundwater in the Kern Canyon Bundle because it is not utilized by the Kern Facility. However, any groundwater in the area is expected to be relatively soft and of high quality.

4.3.5 STANDARDS OF SIGNIFICANCE

For the purpose of this EIR, an impact to hydrology or water quality is considered significant if the project would:

- Expose people or structures to substantially increased flood risk;
- Substantially alter the stability or geomorphology of stream channels by changing the flow or sediment regimes;
- Result in a change in absorption rates or drainage patterns that would increase the rate and amount of surface runoff at a scale that would substantially alter basin hydrology;
- Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level that would not support existing land uses or planned uses for which permits have been granted);
- Reduce flow forecast capability such that the ability to effectively plan and manage operations is substantially impaired; or
- Substantially reduce the available water supply for instream or downstream beneficial uses;
- Substantially degrade groundwater or surface water quality as a result of operation of the project by exceeding adopted RWQCB Basin Plan water quality objectives, applicable NPDES permit requirements, or local standards.

4.3.6 ANALYTICAL METHODS

The evaluation of potential impacts of the project on hydrology and water quality was based on available technical reports, published information, and consultation with knowledgeable individuals. Information obtained from these sources was reviewed and summarized to establish the hydrologic setting provided above. The evaluation of impacts was also based on data generated by hydrologic modeling performed specifically for this study. A summary description of the modeling undertaken to develop data for the evaluation of hydrologic impacts is provided in Chapter 3, Approach to Environmental Analysis, and more detail is provided in Appendix C. Note that the modeling produced data at a monthly time step; therefore, unless otherwise noted, the analyses described below refer to monthly average flows and end of month storages. To make the text more readable, the terms “monthly average” and “end of month” have been dropped when referring to flows and reservoir storages, respectively.

Potential impacts on hydrology and water quality were evaluated assuming the divestiture of Pacific Gas and Electric Company facilities as described in Chapter 3. The extent to which the project could affect flooding, stream geomorphology, water availability, water supply forecasting or water quality, and whether those effects would be significant is based on the general criteria described in the Standards of Significance, above.

In addition to the impacts described in detail below, other effects of the project were considered and found to be less than significant. One such effect was the potential for increased evaporation from lake surfaces as a result of operational changes. Evaporation from lake water surfaces can consume a substantial portion of the available water in a basin, particularly during the critical late summer and early fall seasons. Evaporation from lake surfaces can be up to seven inches or more per month in July and August. For large lakes, this can result in a substantial portion of the total available water supply being lost to evaporation. For example, the average annual evaporative losses from Lake Almanor may be up to 80 taf or more assuming historic operating levels and estimated evaporation. Given the average annual inflow to Lake Almanor of approximately 500 taf, it is clear that evaporation plays an important role in the water balance in this basin. Changes in operations have the potential to affect evaporative losses and thereby the available water supply downstream of the reservoirs. If a reservoir is operated at a higher level, particularly during the summer months, more of the basin’s total water supply will be lost to evaporation. Conversely, if reservoirs are operated at lower levels, less water will be lost to evaporation. However, considering the operational scenarios examined for the project, the change in evaporative losses are estimated to be insignificant relative to the total basin water balance. For example, at Lake Almanor, the operational changes assumed to occur under the WaterMax Scenario would result in an additional average annual evaporative loss of approximately 2 taf. This is approximately 0.2 percent of the total inflow volume to the lake. On smaller reservoirs, or reservoirs for which the project could not cause as significant a change in operations, the increase in evaporative losses would be proportionately smaller. Also, for any reservoirs that are operated at lower levels as a result of the project, evaporative losses would be reduced and the action could have a minor beneficial impact of providing more water for consumptive uses, instream flows, and hydroelectric energy.

4.3.7 INTRODUCTION TO IMPACTS AND MITIGATION MEASURES

For Hydrology and Water Quality, the following impacts have been identified:

- Impact 3-1: The project could increase flood risk as a result of decreases in available reservoir storage due to changes in operations.
- Impact 3-2: The project could alter geomorphology and reduce channel stability as a result of changes in high flows.
- Impact 3-3: The project could alter streamflows as a result of changes to the current program of cloud seeding.
- Impact 3-4: The project could impair the development of long term and short term streamflow volume forecasts and flood flow forecasts as a result of the elimination or substantial reduction in the quantity or quality of cooperative gaging programs (including snow courses, and streamflow, lake level, and precipitation gaging).
- Impact 3-5: The project could reduce instream flows in bypass reaches to less than baseline flows, which could result in a significant impact on water quality, inconsistent with the Basin Plan.
- Impact 3-6: Project changes in reservoir operations and management could result in a significant impact on water quality inconsistent with the Basin Plan.
- Impact 3-7: Project changes in timber harvest practices or extent could result in a significant impact on water quality inconsistent with the Basin Plan.
- Impact 3-8: Construction activities associated with development of Project Lands would involve earthmoving activities that could affect receiving water quality through increased sedimentation.
- Impact 3-9: The project could result in land development that could affect water quality through increases in urban pollutants in stormwater runoff and septic system use.
- Impact 3-10: The project could result in changes in reservoir sediment management practices which could result in a significant impact on water quality, inconsistent with the Basin Plan.

Where impacts are significant, mitigation measures are recommended at the conclusion of the analysis of each impact.

4.3.8 IMPACT 3-1: IMPACT, ANALYSIS, AND MITIGATION MEASURES

Impact 3-1 The project could increase flood risk as a result of decreases in available reservoir storage due to changes in operations (*Significant*).

Reservoirs impound water and regulate flows. Reservoir operations affect the timing and quantity of water stored, which in turn affects the amount of water released and spilled. Although none of the reservoirs operated by Pacific Gas and Electric Company has a defined flood control storage pool, each provides incidental downstream flood control benefits by storing water during high flows for later release for power generation. The larger the reservoir, the greater the potential flood control benefits. It is in the interest of hydropower operators to capture as much of the high flows in excess of plant capacity as possible and save it for later use as needed for power generation. Pacific Gas and Electric Company reservoirs are typically drawn down during the dry summer and fall season and refilled each winter and spring from rainfall and snowmelt runoff. The operations of a particular reservoir establish a de facto level of downstream flood control. To the extent that operations by a new owner differ from the baseline operation, the level of flood control downstream of any reservoir could be affected.

The extent of changes in reservoir operations and the associated risk of increased flooding are evaluated for each regional bundle below. Flood risk has been evaluated for large storage reservoirs only. Smaller, run-of-river type facilities do not provide significant flow attenuation. Thus, operational changes at these facilities would not affect downstream flooding. Potential increases in flood risk were evaluated based on monthly data for reservoir water surface elevation. Reservoir water levels were examined for the baseline condition and the PowerMax and WaterMax Scenarios for four water years (representative of critical, dry, normal, and wet conditions). Substantial increases in reservoir water levels relative to the baseline condition during flood season (generically defined as November through March) were assumed to result in increased flood risk.

4.3.8.1 Impact 3-1: Shasta Regional Bundle

Model results were evaluated for three reservoirs in the Shasta Regional Bundle: Lake Britton, Lake McCloud, and Iron Canyon Reservoir. It was assumed that the lack of storage capacity at the other reservoirs in the Shasta Regional Bundle would preclude any significant downstream flooding impacts due to operational changes. For this bundle, only the PowerMax Scenario was modeled using OASIS. The lack of significant seasonal storage in this regional bundle makes maximizing water supply infeasible, thus the WaterMax Scenario was not modeled.

Lake Britton (Pit River Bundle)

Lake Britton is the largest reservoir in the upper part of the Pit River system. In the baseline scenario, water surface elevations would range between 2,749 and 2,758 feet above sea level, with lower water surface elevations through January and refill of the reservoir commencing between February and April depending on water year type. Under the PowerMax Scenario, water surface elevations typically would be five feet lower than the baseline scenario during the winter when the reservoir would be maintained at lower levels. During the summer months, when water surface elevations would be held higher, the PowerMax Scenario showed essentially the same water levels as the baseline. Therefore, flood risk downstream of Lake Britton is not expected to increase as a result of the project.

Lake McCloud (McCloud-Pit Bundle)

At Lake McCloud, the PowerMax Scenario shows water levels similar to baseline conditions through the winter for all water year types except wet years. In dry and critically dry years, water levels in the spring would sometimes be held lower under the PowerMax Scenario than the baseline. In normal years, water levels in the summer would fluctuate more and typically would be held lower than the baseline. During wet years water levels in Lake McCloud would be maintained equal to or below baseline conditions throughout the year. During winter months in wet years, water levels would typically be held six feet below the baseline water levels. Thus, flood potential downstream of Lake McCloud typically would not be increased as a result of the project.

Iron Canyon Reservoir (McCloud-Pit Bundle)

Iron Canyon Reservoir, which receives inflow from Lake McCloud via a tunnel, would typically be held lower than the baseline levels under the PowerMax Scenario. Water levels under this scenario would also show smaller fluctuations. Fall and winter water surface elevations under the PowerMax Scenario typically would range between zero and 15 feet lower than in the baseline condition, though water levels during the summer months would sometimes exceed the baseline levels. Because of the reduced winter water levels, flood potential downstream of Iron Canyon Reservoir would not be increased due to the project.

Impact to Entire Shasta Regional Bundle

The modeled operational changes could result in changes to reservoir water levels in the Shasta Bundle, but there is no evidence to suggest that flood risk would be increased. An evaluation based on the OASIS modeling data (monthly flows and water levels) indicates that available reservoir storage during the flood season would be maintained or increased under the PowerMax Scenario; thus, flooding would not be increased due to the project, and the impact would be *less than significant*.

4.3.8.2 Impact 3-1: DeSabla Regional Bundle

Model results were evaluated for the three largest reservoirs in the DeSabla Regional Bundle: Lake Almanor, Bucks Lake, and Butt Valley Reservoir. It appears that the lack of significant storage capacity at the other reservoirs in the DeSabla Bundle would preclude any significant impacts from operational changes.

Lake Almanor (Upper North Fork Feather River Bundle)

Lake Almanor is the largest storage facility in the DeSabla system, with a capacity of 1,143,000 acre-feet. In the baseline scenario, water levels would fluctuate by less than 15 feet during any year, with water surface elevations maintained between about 4,469 and 4,494 feet above sea level, depending on the type of water year. Under the PowerMax Scenario, water surface elevations in Lake Almanor would be significantly lower than baseline conditions throughout the year. Water level fluctuations would be consistent with the baseline scenario, but water surface elevations would be up to ten feet lower except during the summer in wet years. In the WaterMax Scenario, water levels would range from ten feet lower than baseline in a critically dry year to five feet higher than the baseline in the dry year examined. Water levels in normal and wet years would typically be held several feet higher than the baseline during the winter flood season.

Higher water levels could potentially lead to increased flood risk, but the modeled change in storage is quite small when compared to the total available storage in Lake Almanor and the potential flood inflow. The OASIS simulated storage in January of the wet year (1983) changed from 883 taf in the baseline scenario to 952 taf in the WaterMax Scenario, an increase of 69 taf. The available storage (below the maximum permissible level of 1,143 taf) for this month would thus drop from 260 taf to 191 taf. The maximum recorded five day inflow to the lake was approximately 126 taf in January 1997. Prior to the 1997 event, the maximum reported 5-day inflow was 85 taf in December 1964. It is evident that Lake Almanor provides significant storage relative to historic inflows, even under the revised operations. Furthermore, a review of USGS stream gaging data for this basin shows that all significant peak flows on the North Fork Feather River between Lake Almanor and Lake Oroville have resulted from high runoff on the uncontrolled East Branch of the NFFR. For example, the peak flow at USGS gage 11403200 (NF Feather River below Rock Creek Diversion Dam) during the January 1997 event was 91,600 cfs. The corresponding peak discharge out of Lake Almanor during this event was less than 2,160 cfs and the mean daily inflow to Lake Almanor on the day following the five day event was approximately 5,500 cfs. Therefore, even if the project filled during this event and passed inflow, its impact on flood flows downstream of the confluence with the East Branch would be *less than significant*.

Butt Valley Reservoir (Upper North Fork Feather River Bundle)

At Butt Valley Reservoir, each of the modeled scenarios results in significant fluctuations in water levels throughout the year. The PowerMax and WaterMax Scenarios would result in differences in water surface elevation ranging from seven feet below to ten feet above the baseline levels. No pattern was evident in the water surface elevation data analyzed for the critical, dry, normal, and wet water years (i.e. the large month to month fluctuations in all scenarios masked any significant operational changes). Review of the stage-frequency data indicates that, with the exception of the month of December, peak water levels in Butt Valley Reservoir would not be affected by the operational scenarios. In December, the simulations show that, under the WaterMax Scenario, water levels would be held approximately three feet higher than the baseline. However, the December water levels typically would still be nine feet below the maximum water levels in other winter months. Thus, the change in storage in Butt Valley reservoir should not appreciably affect flood risk and is considered *less than significant*.

Bucks Lake (Bucks Creek Bundle)

Drawdown patterns in Bucks Lake would be similar to the baseline under both the PowerMax and WaterMax Scenarios. Under the PowerMax Scenario, water levels typically would be 10-20 feet lower than the baseline condition during the winter flood season. Water levels in the WaterMax Scenario would range between five feet higher and 20 feet lower than the baseline water levels during the flood season. A review of the stage frequency results for Bucks Lake indicates that the median lake water level during the flood season (November through March) would increase by up to 11 feet under the WaterMax Scenario, but simulated maximum water levels are unaffected with the exception of February. Under the baseline condition, the winter storage in Bucks Lake would range between 45 and 75 taf. Under the WaterMax Scenario, the storage would range between 17 and 82 taf. Available storage (below the maximum 105 taf) would range between 30 and 60 taf under the baseline and 23 and 88 taf under the WaterMax Scenario. Historic monthly inflows to Bucks Lake are typically less than 10 taf but range as high as 46 taf. Therefore, under the

WaterMax Scenario, the loss of available reservoir storage could affect flood control during some events. However, considering the small change in storage and the relatively minor contribution of Bucks Creek flows to flooding on the NFFR (East Branch NFFR flows range as high as 620 taf/month), the potential for increased flood risk is considered to be *less than significant*.

Impact to Entire DeSabla Regional Bundle

The modeled operational scenarios result in changes to reservoir water levels in the DeSabla Bundle, but the potential impact on flooding is considered less than significant. The WaterMax Scenario, in particular, would increase water levels in Lake Almanor and Bucks Lake, reducing the storage available to attenuate high flows. However, considering the relatively small changes in modeled reservoir storage, and the dominance of East Branch NFFR flows on flooding in this region, the storage reduction is not likely to lead to significant increases in flood risk.

4.3.8.3 Impact 3-1: Drum Regional Bundle

In general, the potential for increased flood risk as a result of the assumed operational changes is believed to be small in the Drum Regional Bundle due to the lack of operational flexibility and the limited storage in Pacific Gas and Electric Company facilities within this bundle (Harrison, 2000). However, model results were evaluated for three reservoirs in the Drum Regional Bundle to provide a quantitative analysis of the operational changes expected under the PowerMax and WaterMax Scenarios. The reservoirs selected for detailed analysis included Lake Pillsbury, Fordyce Lake, and Lake Spaulding. These reservoirs provide a substantial portion of the available storage in Pacific Gas and Electric Company facilities in this bundle. The lack of storage capacity at many other reservoirs in this regional bundle precludes significant flooding impacts due to operational changes. Note that the WaterMax Scenario was not modeled for the Potter Valley system (Lake Pillsbury) as it was determined that the baseline scenario matches operations that would be seen under the WaterMax Scenario.

Lake Pillsbury (Potter Valley Bundle)

At Lake Pillsbury, the PowerMax Scenario would result in generally higher water levels than the baseline condition except during the wet year analyzed. During the flood season in normal years, the lake would be maintained at levels up to ten feet higher than the baseline under the PowerMax Scenario. Smaller increases in lake levels would be expected during dry and critical years. During wet years, the lake typically would be maintained at levels closer to the baseline condition throughout the flood season. A review of the stage-frequency results for Lake Pillsbury indicates that the median lake water level during the flood season (November through March) would be unchanged except in December, when it would be increased by about nine feet under the PowerMax Scenario. Simulated maximum water levels would be unaffected by the operational changes. Considering that the median lake water level in December is about 20 feet below the median water level for the months of January through March, and that water levels in these months are unaffected by the operational changes, the potential impact of increased flood risk as a result of the project is considered *less than significant*.

Fordyce Lake (South Yuba River Bundle)

At Fordyce Lake, both the PowerMax and WaterMax Scenarios would result in water levels similar to the baseline. Winter lake stages would typically range between 20 and 60 feet under all scenarios for all water year types. The only exception to this would be the baseline scenario, where simulated stages reached approximately 75 feet in November 1982 (wet year). Flood season maximum deviations between baseline conditions and the PowerMax Scenario range from an increase of 15 feet to a decrease of 40 feet. Corresponding differences between the baseline and WaterMax Scenarios range from an increase of 10 feet to a decrease of 40 feet. Typical lake stages in the flood season would range between 20 and 50 feet. Over the entire year, Fordyce Lake stages would range between 20 feet and 120 feet, typically reaching a maximum at the end of the month of May. Based on the stage-frequency results, the maximum decrease in available storage during winter months would be less than 5 taf. Considering that monthly inflows to Fordyce Lake range as high as 150 taf, the effect of this loss of storage would be *less than significant*.

Lake Spaulding (South Yuba River Bundle)

At Lake Spaulding, both the PowerMax and WaterMax Scenarios would result in similar water levels to the baseline condition in all months except the early flood season (November) in the 1983 wet year. In that month, the water level in Spaulding would be approximately 35 feet higher under the alternative scenarios compared to the baseline. Water levels later in the flood season (December through March) would be maintained within about 5 feet of the baseline condition (typically lower) in both scenarios for all water year types. The increased water level in 1983 appears to be an anomaly, as the stage-frequency data suggest that baseline median and peak water levels typically would be reduced or held the same under the PowerMax and WaterMax Scenarios. Thus, the changes in operations under the PowerMax and WaterMax Scenarios do not lead to any significant increase in flood risk.

Impact to Entire Drum Regional Bundle

The modeled operational changes indicate that water levels in Lake Pillsbury, Fordyce Lake, and Lake Spaulding may be above baseline levels during certain months in the flood season; however, the differences would be small and not likely to affect flood risk. Thus, the project impact on flood risk in the Drum Regional Bundle is *less than significant*.

4.3.8.4 Impact 3-1: Motherlode Regional Bundle

Model results were evaluated for four reservoirs in the Motherlode Regional Bundle: Salt Springs Reservoir and Blue Lakes on the NF Mokelumne River, Lower Bear Reservoir on the Bear River, and Pinecrest Lake (Strawberry Reservoir) on the SF Stanislaus River. These reservoirs provide most of the available storage in the Motherlode Regional Bundle and as such were felt to provide a reasonable indication of the potential for flood impacts. Pacific Gas and Electric Company facilities on the Merced River as well as other reservoirs in this bundle do not provide significant storage, thus significant flooding impacts due to operational changes at these facilities are unlikely.

Salt Springs Reservoir (Mokelumne River Bundle)

At Salt Springs Reservoir, water levels under the PowerMax Scenario would be reduced relative to the baseline condition during the winter flood season. The reduced storage was seen in both the plotted water years and the stage frequency data. Under the WaterMax Scenario, water levels would be at or below the baseline condition over the majority of the four water years analyzed with the exception of winter months in the dry year, when water levels were held up to 50 feet higher. However, a review of the stage frequency data for this scenario indicates that the median water levels throughout the winter would be increased substantially and the maximum water levels in January through March would also be increased. Under the WaterMax Scenario, the available storage in December would be decreased from 107 taf to 82 taf, a difference of 25 taf. The available storage in other months during the winter flood season would be similarly reduced. The decrease in available reservoir storage during flood season indicates that the project could result in an increased risk of downstream flooding. For example, during the severe storm of January 1997, the maximum daily inflow to Salt Springs Reservoir was greater than 20,000 cfs while the maximum outflow was limited to 5,900 cfs, and occurred several days after the peak inflow. The USGS storage data for this event indicate that the reservoir captured approximately 80 taf in the three days prior to the peak release, and that the reservoir came within approximately 7 taf of its capacity. Under the simulated operation for the WaterMax Scenario, the reservoir would have filled earlier in the flood and the peak release would have been higher. Therefore, reaches downstream of the facility could be subject to increased flood flows under the WaterMax Scenario. Although topographic mapping of the NF Mokelumne River indicates that the reach between Salt Springs Reservoir and Pardee Reservoir is mostly uninhabited, the potential for increasing flood risk to people or structures is nonetheless considered *significant*.

Blue Lakes (Mokelumne River Bundle)

At Blue Lakes, simulated water levels under both the PowerMax and WaterMax Scenarios are nearly identical to the baseline condition during the winter flood season. Therefore, flood attenuation within this facility should not be affected by the project and there is *no impact* on flood risk.

Lower Bear Reservoir (Mokelumne River Bundle)

At Lower Bear Reservoir, storage under the PowerMax Scenario would be maintained the same as in the baseline scenario during the winter flood season of normal and wet years. Under the WaterMax Scenario, storage would be increased relative to the baseline condition over much of the flood season in each of the four water years analyzed. In the wet year (1983), simulated storage levels in the reservoir would be up to 20 taf higher under the WaterMax Scenario when compared to the baseline. Higher storage levels in Lower Bear Reservoir would result in less incidental flood control and could lead to higher discharges from the facility. Therefore, reaches downstream of Lower Bear Reservoir could be subject to increased flood flows under the WaterMax Scenario. Although topographic mapping of this watershed indicates that the reaches between Lower Bear Reservoir and Pardee Reservoir are mostly uninhabited, the potential for increasing flood risk to people or structures is nonetheless considered *significant*.

Pinecrest Lake (Strawberry Reservoir) (Stanislaus River Bundle)

At Pinecrest Lake, water levels under the PowerMax Scenario would typically be the same as the baseline conditions. Under the WaterMax Scenario, water levels would be higher than the baseline during the flood season for each of the indicator water years analyzed. A review of the stage frequency data for this scenario indicates that the median and maximum water levels throughout the winter are increased by two to three taf. Thus, the available storage in December and January would be typically decreased from 11 taf to eight taf. The available storage in other months during the winter flood season would also be reduced. A decrease in available reservoir storage during flood season could result in a reduction in flow attenuation and a commensurate increase in downstream flood risk. During the January 1997 flood event the maximum daily inflow to the facility was approximately 6,400 cfs while the maximum daily outflow was limited to 4,680 cfs. The USGS data show that the reservoir captured approximately eight taf of the total inflow of approximately 20 taf in the three days prior to the peak release. If the available storage in this facility were reduced, as indicated under the WaterMax Scenario, higher discharges could result. This would lead to increased downstream flood risk that is considered *significant*.

Impact to Entire Motherlode Regional Bundle

The modeled scenarios indicate that water levels at Salt Springs Reservoir and Lower Bear Reservoir on the NF Mokelumne System and Pinecrest Lake (Strawberry Reservoir) on the SF Stanislaus River would be held higher under the WaterMax Scenario compared to the baseline condition. This would be particularly true during the flood season, when available storage for flood control is most critical. The decrease in available reservoir storage could result in higher flood discharges from the facilities. Review of available mapping for the NF Mokelumne River basin indicates that the river reaches downstream from the Pacific Gas and Electric Company facilities are mostly uninhabited and as such the potential for increasing flood risk to people or structures may not be great. On the SF Stanislaus River, on the other hand, Pinecrest Lake lies just upstream of the town of Strawberry and any increase in peak flows has the potential to exacerbate flooding. Due to the impact to the Salt Springs Reservoir, the Lower Bear Reservoir and Pinecrest Lake, flood risk in the Motherlode Regional Bundle is considered *significant*.

4.3.8.5 Impact 3-1: Kings Crane-Helms Regional Bundle

OASIS model results were evaluated for only one reservoir in the Kings Crane-Helms Regional Bundle: Bass Lake. This is the only reservoir in the regional bundle that has both substantial storage and operational flexibility. Several other reservoirs in the bundle, namely Courtright and Wishon Reservoirs, were evaluated based on operational constraints, even though OASIS model data were not available. These reservoirs were not modeled because the lack of operational flexibility precludes significant changes in operations. For the remaining reservoirs in this bundle, the lack of storage capacity constrains operations and minimizes potential flooding impacts as a result of the project.

Bass Lake (Crane Valley Bundle)

Bass Lake is part of the Crane Valley Facility (FERC 1354) and is the primary storage facility on the Willow Creek System. It has a storage capacity of 45,410 acre-feet and a maximum depth of about 100 feet. In the baseline condition, Bass Lake is drawn down a maximum of about 23 feet (elevation 3,353 feet) from full pool (elevation 3,376.4 feet) in any year, providing about 22,000 acre-feet of available storage. Under the PowerMax Scenario, the water surface elevation of Bass Lake would be 25 to 28 feet lower at the end of December compared to the baseline condition. Under the WaterMax Scenario, Bass Lake water levels in the flood season would be similar to the baseline condition during normal and wet years. In dry and critical years, Bass Lake water surface elevations would average about 5five to seven feet lower than under baseline conditions at the end of December. Thus, no increased risk of flooding is expected to occur as a result of the project.

Manzanita Lake, Kerckhoff Reservoir, Black Rock Reservoir, Balch Afterbay

Manzanita Lake, Kerckhoff Reservoir, Black Rock Reservoir and the Balch Afterbay are utilized as powerhouse regulating reservoirs and are subject to high, but brief, fluctuations. These reservoirs are too small to be operated as seasonal storage facilities. Under the PowerMax and WaterMax Scenarios, operation of these reservoirs would be similar to the baseline conditions. Thus, *no change* in flood risk is expected.

Courtright Reservoir and Wishon Reservoir (Kings River Bundle)

Courtright and Wishon Reservoirs are part of the Haas-Kings River Facilities (FERC 1988) and are the primary storage facilities on the North Fork Kings River system. Courtright Reservoir has a usable storage capacity of 123,300 acre-feet and a surface area at full pool of 1,632 acres. Wishon Reservoir has a storage capacity of about 129,000 acre-feet and a surface area at full pool of 1,025 acres.

OASIS modeling was not used to determine water levels under different operational scenarios for Courtright and Wishon Reservoirs. These reservoirs are currently operated to retain as much water as possible, while leaving sufficient space for pump and release operations. This operation is designed to maximize water recycling during the highest load/price periods through mid-September. The current method of operation is expected to continue after divestiture, regardless of who the new owner is. Therefore, no differences in water levels Courtright and Wishon Reservoirs are expected under the operational scenarios and no significant flood impact is expected.

Impact to Entire Kings Crane-Helms Regional Bundle

The modeled operational changes indicate that water levels in Bass Lake would be the same under the PowerMax Scenario and would be below baseline levels under the WaterMax Scenario. Thus, the available storage to attenuate high flows would be maintained or increased relative to the baseline. The increase in available reservoir storage during flood season means the project would not result in an increased risk of flooding. Due to operational or storage constraints, the operation at other facilities in this bundle would not be changed from the baseline operation and flood risk will therefore not be affected.

4.3.8.6 Evaluation of Impact 3-1 to Entire System

Significant increases in potential flood risk were identified in the Motherlode Regional Bundle at Salt Springs Reservoir and Upper Bear Reservoir in FERC license 0137 and at Pinecrest Lake (Strawberry Reservoir) in FERC license 2130. Therefore, the impact of the project of flood risk is considered *significant* for the entire system.

4.3.8.7 Impact 3-1: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-1: Prior to the transfer of title for the Mokelumne River Bundle (FERC 137) and the Stanislaus River Bundle (FERC 2130), Pacific Gas and Electric Company shall prepare a High Flow Scheduling Plan acceptable to the CPUC that would be binding upon the new owner(s). The High Flow Scheduling Plan will document the steps necessary to ensure that the incidental flood control provided by the pertinent reservoirs under the baseline operation is maintained.

4.3.8.8 Impact 3-1: Level of Significance after Mitigation

Less than significant.

4.3.9 Impact 3-2: Impact, Analysis, and Mitigation Measures

Impact 3-2: The project could alter geomorphology and reduce channel stability as a result of changes in high flows (*Significant*).

Fluvial geomorphology involves a balance of discharge and sediment loads, with a stream channel eventually developing a stable form adapted to the range of flow and sediment input it experiences. High flows are responsible for most sediment transport, so increases in peak flows could lead to significant erosion. Sediment accumulation is not typically a problem in steeper stream reaches typical of the project setting, but large decreases in peak flow could affect the sediment balance and geomorphic instability. Geomorphology is also affected by the flashiness of the streamflow hydrograph and the relative magnitude and duration of flood flows compared to normal flows. A new owner with a different water management strategy could make operational changes at Pacific Gas and Electric Company facilities that would affect flows, with potentially significant geomorphic impacts. For this analysis, geomorphic impacts associated with the project were assumed to occur under the following conditions:

- an increase of ten percent or more in average annual maximum flow,
- an increase of ten percent or more in the average of the ratio of annual maximum to annual mean flow for each year,
- a decrease of 20 percent or more in average annual maximum flow, or
- a change of 20 percent or more (increase or decrease) in the average annual flow for any month

The final criterion was only applied for those months where the flow in the baseline scenario was greater than the mean annual flow plus one standard deviation. Changes in flows during low flow periods (when not accompanied by any of the other changes listed above) are not likely to cause significant geomorphic impacts because these flows remain within the natural variability of the system and because lower flows have less sediment transport capability.

Impacts were evaluated for each OASIS modeled stream reach in each Regional Bundle. For stream reaches that were not modeled, it was determined that geomorphic impacts would be less than significant, as the operational flexibility in those systems is insufficient to allow substantial alterations in streamflows.

A full assessment of potential geomorphic impacts of the project requires complete and accurate information about existing geomorphic problems and sensitivity to morphologic change. To our knowledge this information is not currently available. According to the Pacific Gas and Electric Company the facilities included in the proposed divestiture lie primarily in granitic bedded rivers, and as such the geomorphology is stable and cannot be significantly altered by project operations (PG&E Co., 2000f). The Company's response to a request for information about known geomorphic problems in the stream reaches downstream of the facilities yielded five documents describing geomorphic assessments on the North Fork Feather and North Fork Mokelumne rivers (PG&E Co., 2000g). (Documents on the Kings River received in response to the same request were not relevant to evaluation of the geomorphic impact.) Where available, the Company supplied information regarding geomorphic sensitivity has been incorporated into the following discussion.

4.3.9.1 Impact 3-2: Evaluation of Impact to Shasta Bundle (*Less Than Significant*)

There would be no significant changes in high flows under the PowerMax Scenario compared to the baseline scenario. Geomorphic impacts of the project on the Shasta Bundle would therefore be less than significant. As discussed above, the WaterMax Scenario was not modeled for this bundle due to the absence of seasonal storage.

4.3.9.2 Impact 3-2: Evaluation of Impact to DeSabla Bundle (*Significant*)

Changes in flows exceeding the identified thresholds were modeled in five reaches under the PowerMax Scenario and four reaches under the WaterMax Scenario. Geomorphic assessments of the North Fork Feather River (NFFR) below the East Branch NFFR and between Rock Creek and Cresta dams performed for Pacific Gas and Electric Company indicate that moderate changes in flows and sediment supply are unlikely to have an impact on channel morphology in these reaches (Resource Consultants and Engineers, 1992; Resource Consultants and Engineers, 1994). Regardless of the geomorphic sensitivity, no significant flow changes were identified based on the modeled data for those reaches.

NFFR Below Lake Almanor (Upper North Fork Feather River Bundle)

This reach would experience an increase in the average annual maximum flow by 22 percent under the PowerMax Scenario, resulting due to an increase in December releases from Lake Almanor. In the WaterMax Scenario, November and December flows would be reduced by 44 and 31 percent, respectively, essentially eliminating month to month flow variability. These changes could lead to substantial geomorphic impacts on the stream channel and are considered significant.

Butt Creek Below Butt Valley Reservoir and NFFR below Belden Reservoir (Upper North Fork Feather River Bundle)

Both of these reaches receive only occasional flows due to spill from the upstream reservoirs. Although the reaches would experience some decrease in annual maximum flows under both the PowerMax and WaterMax Scenarios, any resulting geomorphic impacts are not considered significant.

NFFR Above East Branch NFFR (Upper North Fork Feather River Bundle)

This reach would experience a 12 percent increase in the maximum to mean ratio under the PowerMax Scenario, and a 20 percent reduction in average flows during the month of May (the month with highest average flow in the baseline scenario). Under the PowerMax Scenario the average December flow would increase by 31 percent, and December would become the month with the highest average flow. In the WaterMax Scenario, this reach would experience a 14 percent increase in maximum flow (but no change in the month of occurrence (i.e. the maximum would still occur in April)). The geomorphic impacts of these changes are considered *significant*.

Bucks Creek Below Lower Bucks Lake (Bucks Creek Bundle)

This reach would experience a 37 percent reduction in average annual maximum flow under the PowerMax Scenario compared to baseline conditions. Under the WaterMax Scenario, this reach would experience a 15 percent increase in average annual maximum and a 23 percent increase in the average ratio of annual maximum to annual mean flow. The geomorphic impacts of these changes are considered *significant*.

Impact to Entire DeSabla Regional Bundle

Several natural stream reaches in the upper NFFR system would experience significant changes in high flows under the PowerMax and/or WaterMax Scenario. Large changes in high flows indicate *significant* geomorphic impacts.

4.3.9.3 Impact 3-2: Evaluation of Impact to Drum Regional Bundle (*Significant*).

Flow changes exceeding the identified thresholds were modeled in two reaches under the PowerMax Scenario and two reaches under the WaterMax Scenario in the Drum-Spaulding system. No significant geomorphic impacts resulting from flow changes were identified in the Potter Valley system.

North Yuba River below New Bullards Bar Reservoir (Outside Pacific Gas and Electric Company Bundles)

This reach would experience decreases in February flows of greater than 20 percent under both the PowerMax and WaterMax Scenarios. These decreases would result in a reduction in sediment transport capacity, thereby causing significant geomorphic impacts on the channel.

Oregon Creek below Log Cabin Diversion Dam (Outside Pacific Gas and Electric Company Bundles)

This reach would experience a 43 percent increase in the average annual maximum flow, as well as significant increases in January and February flows, under the WaterMax Scenario. These changes would create an additional month of high flows, which could lead to severe erosion. The PowerMax Scenario would also produce significant changes in January and February flows, but in that scenario, high flows would be shifted from January to February rather than increasing in both months. This change should not significantly affect geomorphology. However, the changes under the WaterMax Scenario would have *significant* geomorphic impacts.

Impact to Entire Drum Regional Bundle

Several natural stream reaches in the Yuba River system would experience significant changes in high flows under the PowerMax or WaterMax Scenarios. Large changes in high flows indicate *significant* geomorphic impacts.

4.3.9.4 Impact 3-2: Evaluation of Impact to Motherlode Bundle (*Significant*)

In the Mokelumne system, changes in flows exceeding the identified thresholds were modeled in three reaches under the PowerMax Scenario and five reaches under the WaterMax Scenario. No flow changes exceeding the thresholds would occur in the Stanislaus system.

A geomorphic assessment of the Mokelumne River Project performed for Pacific Gas and Electric Company reported that most sites in the North Fork Mokelumne River (NFMR) basin are insensitive to morphologic change in response to project operations but identified nine study sites with moderate to high sensitivity (see Table 4.3-48) (EA Engineering, Science, and Technology, 2000).

Cole Creek below Cole Creek Diversion Dam, Bear River below Tiger Creek Conduit, and Panther Creek below Tiger Creek Conduit (Mokelumne River Bundle)

Each of these reaches typically carries only minimal bypass flows with occasional large spill flows. Although they would experience substantial changes in average annual maximum flows under the PowerMax and/or the WaterMax Scenario, in all cases these changes are attributable to a single spill event and thus would not be expected to have significant geomorphic impacts. Although Panther Creek is classified as moderately sensitive to facility operations, morphologic changes from a single event are not deemed sufficient to constitute a significant impact.

Tiger Creek Conduit Bypass to NFMR (Mokelumne River Bundle)

This reach would experience an 11 percent increase in average annual maximum flow under the WaterMax Scenario. This change could have *significant* geomorphic impacts on the NFMR.

NFMR below Bear River, NFMR below Panther Creek, and NFMR below Tiger Creek Afterbay (Mokelumne River Bundle)

These reaches would experience substantial increases in the ratio of the average annual maximum to annual mean flow. This increase indicates changes in the hydrograph pattern that could affect sediment transport capacity, with *significant* geomorphic impacts.

Impact to Entire Motherlode Regional Bundle

Several natural stream reaches in the NFMR system would experience substantial changes in high flows under one or both scenarios. Large changes in high flows and hydrograph patterns indicate *significant* geomorphic impacts.

4.3.9.5 Impact 3-2: Evaluation of Impact to Kings Crane-Helms Bundle (*Significant*)

Flow changes exceeding the identified thresholds were modeled in four reaches under the PowerMax Scenario and three reaches under the WaterMax Scenario.

North Fork Willow Creek (NFWC) below Bass Lake, NFWC below Crane Valley Powerhouse Return, NFWC below Manzanita Lake, and NFWC below North Fork Diversion (Crane Valley Bundle)

All four of these reaches would experience substantial reductions in maximum flows under the PowerMax Scenario (from 32 to 48 percent when compared to the baseline scenario). All but the NFWC below Manzanita Lake would also see substantial reductions (21 to 30 percent) in the average annual maximum flow under the WaterMax Scenario. These changes would have *significant* geomorphic impacts on North Fork Willow Creek.

Impact to Entire Kings Crane-Helms Regional Bundle

Several natural stream reaches in the Crane Valley system experience substantial changes in high flows under the alternative operation scenarios. Large changes in high flows could have *significant* geomorphic impacts.

4.3.9.6 Evaluation of Impact 3-2 to Entire System

Changes in operation of Pacific Gas and Electric Company facilities by new owners could have *significant* impacts on the geomorphology of natural stream channels within the system

4.3.9.7 Impact 3-2: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-2: Prior to the transfer of title for the Upper North Fork Feather River bundle, the Bucks Creek bundle, the Mokelumne River bundle, or the Crane Valley bundle, Pacific Gas and Electric Company shall establish, in consultation with the Resources Agency, and in a manner satisfactory to the CPUC, maximum allowable migration limits or maximum deposition limits for geomorphically active and sensitive areas of the affected stream reaches identified above. Prior to or concurrent with the transfer of title for these bundles, the new owner shall by binding written instrument, agree to monitor stream geomorphology and take counteractive measures as necessary to protect downstream sensitive areas. The monitoring program shall include cross section surveys in these reaches to establish a baseline condition for future comparison, a program for routine resurveying and monitoring to identify changes in channel form and bed and bank conditions, and a plan of action to modify operations if significant geomorphic changes are observed. The written instrument shall also specify that if operational changes fail to alleviate the geomorphic problems caused by the post-divestiture operations, physical measures to control erosion in eroding reaches or dredging of aggraded reaches shall be instituted.

Level of Significance after Mitigation

Less than significant.

4.3.10 IMPACT 3-3: IMPACT, ANALYSIS, AND MITIGATION MEASURES

Impact 3-3: The project could alter streamflows as a result of changes to the current program of cloud seeding (*Significant*).

4.3.10.1 Impact 3-3: Motherlode and DeSabla Regional Bundles

Pacific Gas and Electric Company seeds winter storms in the Motherlode and DeSabla regions (Lake Almanor and the Upper Mokelumne River) with ground-based silver-iodide generators.

Pacific Gas and Electric Company currently performs no cloud seeding within the Shasta, Drum, or Kings Crane-Helms regions although it contributes some money to the Kings River project run by the Kings River Conservation District (personal communication, Maury Roos, DWR 8-8-00). Although it is difficult to accurately measure the efficacy of cloud seeding, past evaluations of seeding program success range from a 5 percent to a 25 percent increase in precipitation and a 2 percent to a 15 percent increase in runoff (TID/MID DEIR, 1990), (Peracchio et. al.1995). It is generally acknowledged that ground-based seeding operations increase runoff by five percent.

A new owner may decide to eliminate or reduce the cloud seeding operations currently conducted by Pacific Gas and Electric Company. This action could cause environmental impacts including a reduction in the total available runoff volume for consumptive purposes, hydroelectric generation, and instream flows. Considering the assumed 5 percent additional runoff volume resulting from current cloud seeding operations, the reduction in streamflows would be a *significant* impact.

4.3.10.2 Impact 3-3: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-3: Prior to or concurrent with the transfer of title for assets within the Motherlode or DeSabla bundles, the new owner shall, by binding written instrument, agree to continue Pacific Gas and Electric Company's current cloud seeding program or implement an enhanced program of cloud seeding.

4.3.10.3 Impact 3-3: Level of Significance after Mitigation

Less than significant.

4.3.11 IMPACT 3-4: IMPACT, ANALYSIS, AND MITIGATION MEASURES

Impact 3-4: The project could impair the development of long term and short term streamflow volume forecasts and flood flow forecasts as a result of the elimination or substantial reduction in the quantity or quality of cooperative gaging programs (including snow courses, and streamflow, lake level, and precipitation gaging) (*Significant*).

4.3.11.1 Impact 3-4: Evaluation of Impact to Entire System

Pacific Gas and Electric Company measures snow courses and operates data collection stations that measure precipitation, reservoir storage levels, and stream flows. Pacific Gas and Electric Company shares the data collected with the California Department of Water Resources (DWR), as well as the National Weather Service (NWS) and U.S. Geological Survey (USGS). DWR uses this data for forecasting expected runoff and water supply. Pacific Gas and Electric Company collects and shares this data based on cooperative agreements and, primarily, unwritten informal agreements.

If the Pacific Gas and Electric Company's hydroelectric generation facilities and associated assets are divested, it is reasonable to assume there would be more than one winning bidder and the ownership of the current system would be fragmented. Various agencies commented during the scoping phase of this analysis that this could have serious implications for the integrity and reliability of the current hydrometeorologic data collection and forecasting system. If the new owners are not fully informed of the informal data collection and sharing agreements between DWR and Pacific Gas and Electric Company and/or are not required to commit to continue in good faith to carry out Pacific Gas and Electric Company's data collection and sharing responsibilities on a cooperative basis, they may choose not to collect and share some or all of the data. The new owners may also lack the economies of scale and scope, or the financial means, that have made it practicable for Pacific Gas and Electric Company to undertake this level of data collection and sharing.

The loss or qualitative degradation of the data currently collected by Pacific Gas and Electric Company could cause a variety of environmental impacts. Electricity generators and distributors need the data and forecasts to effectively manage their production and ensure optimum use of the water resource. Agricultural interests need the information to determine crop planting patterns, groundwater pumping needs, and irrigation schedules to minimize waste. Operators of flood control projects need the data to assess flood storage potential in reservoirs and develop flood inflow forecasts. DWR needs reliable data to determine how much water the State Water project (SWP) will be able to supply and how to deliver that supply in a given year. Public and private water utilities need the information to evaluate their water supply and determine whether (in a dry year) water rationing may be needed. Both operators and users of recreational resources need the data to determine, for example, ski conditions in the winter and rafting conditions year round. Instream flow targets in many rivers are also dependent on flow forecasts.

The direct impact of losing the data Pacific Gas and Electric Company currently provides would be a reduction in the quality, reliability, and completeness of the information used to forecast water supply, river flows, and potential flood conditions. There could be many indirect environmental impacts. For example, unanticipated flooding due to inaccurate or incomplete information on snow pack, runoff, precipitation, stream flows, or reservoir levels could damage homes, businesses, farmlands, wildlife habitat, and water quality. Missing or unreliable data could lead to an unreliable forecast of available water supply in a given year, so that water suppliers and users make inappropriate choices on reservoir storage levels needed to maintain water supply and fish flows. Similar potential impacts could be felt wherever reliable water supply forecasts and flood forecasts are necessary. In addition, determination of the hydrologic year type classifications, which affects water management in the Bay/Delta, would be adversely affected. An error in, or an increase in the uncertainty of, the year type classification may result in environmental damage and less efficient water management. These impacts are considered *significant*.

4.3.11.2 Impact 3-4: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-4: Prior to or concurrent with the transfer of title for any bundle, new owners shall by binding written instrument agree to assume Pacific Gas and Electric Company's current responsibilities for data collection and sharing agreements and arrangements with DWR, NWS, and USGS on a cooperative basis. The written instrument shall specify that the appropriate cooperating agency (i.e. DWR, NWS, or USGS) shall be consulted and grant approval prior to the modification or discontinuation of any existing cooperative gaging operations.

4.3.11.3 Impact 3-4: Level of Significance After Mitigation

Less than significant.

4.3.12 Impact 3-5: Impact, Analysis, and Mitigation Measures

Impact 3-5: The project could reduce instream flows in bypass reaches to less than baseline flows which could result in a significant impact on water quality, inconsistent with the Basin Plan (*Significant*).

For this EIR the potential for water quality impacts was assessed based on changes in streamflows, and more specifically on the occurrence of flow reductions during periods of low flow. This approach is consistent with the Clean Water Act's recognition that water quality degradation may occur due to "changes in the movement, flow, or circulation of any navigable waters." Furthermore, the U.S. Supreme Court's opinion in *PUD No. 1 of Jefferson County v. Washington Department of Ecology* affirmed that water quality is closely linked to water quantity and that the CWA does not specifically distinguish between the regulation of water quantity and quality (PUD No. 1, 1994).

As described in Section 3.9.1, potential operational changes that may result from the project could affect the timing and quantity of discharges from hydroelectric facilities. This could result in substantial water quality impacts, including increases in turbidity. Concentrations of other pollutants could also be increased with decreased flows, and summer stream temperatures could also be adversely affected. Note that for purposes of this EIR temperature related water quality impacts were evaluated in Section 4.4, Fisheries and Aquatic Resources. Thus, the analyses and results described below are intended to identify potential impacts on water quality parameters other than temperature.

It is impossible to define a single criterion for flow changes that would realistically identify significant impacts across the entire spectrum of streams affected by Pacific Gas and Electric Company facilities. However, it is likely that turbidity and pollutant concentrations are most likely to reach critical levels during low flow periods. Therefore a performance measure which concentrated on low flows was defined. Based on professional judgment a threshold of significance for this impact was defined as a 20 percent decrease in low flows over at least 10 percent of the time periods analyzed. Low flows were defined as conditions where either the baseline flow or the flow in the project scenario was less than or equal to the lowest long-term average monthly flow under the baseline scenario. Thus, this standard considers flow reductions during periods when baseline flows are low, as well as operational changes that would result in additional low flow periods. At locations with documented existing water quality problems, i.e. those reaches classified as impaired water bodies under the CWA California 303(d) listing, lower thresholds were applied in the evaluation of impacts. In these reaches any decrease in flows during low flow periods was identified as significant. Thus, the occurrence of even a 1 percent decrease in low flows for one month would result in a finding of significance.

Streamflow reductions were evaluated using results from the OASIS simulation model. Reaches that would experience significant reductions in low flows (as described above) during any part of the year are identified in the discussions below. It was assumed that unmodeled reaches offer insufficient operational flexibility to substantially alter streamflow patterns. Therefore, potential impacts were presumed to be *less than significant* in these reaches.

4.3.12.1 Impact 3-5: Evaluation of Impact to Shasta Regional Bundle (Significant)

Two reaches in the Shasta Region would experience significant streamflow reductions under the PowerMax Scenario, as shown in Table 4.3-47. (The WaterMax Scenario was not modeled for the Shasta Region.) None of the modeled reaches are in listed impaired watersheds, so the threshold for defining flow reductions was set as a 20 percent reduction relative to the baseline condition. The table indicates the percent of the months modeled in which the flows would be below the identified threshold flow. Streamflow reductions in the Shasta Regional Bundle, as shown in Table 4.3-47, could result in *significant* water quality impacts.

4.3.12.2 Impact 3-5: Evaluation of Impact to DeSabla Regional Bundle (Significant)

Several reaches in the DeSabla Region would experience significant streamflow reductions, as shown in Tables 4.3-48 and 4.3-49 for the PowerMax and WaterMax Scenarios, respectively. None of the modeled reaches are in listed impaired watersheds, so the threshold for defining flow reductions was set as a 20 percent reduction relative to the baseline condition. The tables indicate the percent of the months modeled in which the flows would be below the identified threshold flow.

Table 4.3-47
NFMR Sites With Geomorphic Sensitivity to Hydroelectric Facility Operations

Reach	Sensitivity to Operations
Middle Blue Creek	High
Upper Meadow Creek	High
Lower Meadow Creek	High
Blue Creek	High
Deer Creek	High
NFMR below Salt Springs Dam	Moderate
East Panther Creek below Diversion	Moderate
Tiger Creek below Regulator Reservoir	Moderate
Mokelumne River below Electra PH	Moderate

Source: EA Engineering, Science, and Technology, 2000

Streamflow reductions in the DeSabla Regional Bundle, as shown in Tables 4.3-48 and 4.3-49, could result in *significant* water quality impacts.

4.3.12.3 Impact 3-5: Evaluation of Impact to Drum Regional Bundle (Significant)

Several reaches in the Drum Region would experience significant streamflow reductions, as shown in Table 4.3-50 and Table 4.3-51 for the PowerMax and WaterMax Scenarios, respectively. (The WaterMax Scenario was not modeled for the Potter Valley bundle.) The Upper Main Fork Eel River and Lake Pillsbury are listed under CWA 303(d), so the threshold for evaluation of impacts in the Potter Valley bundle was assumed to be any decrease in low flows relative to the baseline condition. The remaining modeled reaches are not 303(d) listed, so the threshold for defining flow reductions was set as a 20 percent reduction relative to the baseline condition. The table indicates the percent of the modeled months in which the flows would be below the identified threshold flow. Streamflow reductions in the Drum Regional Bundle, as shown in Tables 4.3-50 and 4.3-51, could result in *significant* water quality impacts.

4.3.12.4 Impact 3-5: Evaluation of Impact to Motherlode Regional Bundle (Significant)

Several reaches in the Motherlode Region would experience significant streamflow reductions, as shown in Table 4.3-52 and Table 4.3-53 for the PowerMax and WaterMax Scenarios, respectively. None of the modeled reaches are in listed impaired watersheds, so the threshold for defining flow reductions was set as a 20 percent reduction relative to the baseline condition. Although not listed on the 303(d) list, the East Bay Municipal Utility District (EBMUD) has raised concerns about potential water quality impacts of the project on the Mokelumne River (EBMUD, 2000). EBMUD is particularly concerned about the timing of inflows to Pardee Reservoir and their impact on reservoir water quality. EBMUD notes that the Lower Mokelumne River is listed on the 303(d) list for copper and zinc. The 303(d) listing notes that the source for these pollutants is abandoned

Table 4.3-48 Shasta Low Flow Reductions - PowerMax Scenario (Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
McCloud R abv Ah-Di-Nah					32	16						
McCloud R blw Ah-Di-Nah					24	12						

Source: northwest hydraulic consultants, inc.

Table 4.3-49 DeSabla Low Flow Reductions - PowerMax Scenario (Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Below Mountain Meadows Reservoir										20		
Bucks Lake to Lower Bucks Lake		16	20		12							
Bucks Creek blw Lower Bucks Lake		16	16									
NFFR abv Cresta Reservoir											16	

Source: northwest hydraulic consultants, inc.

Table 4.3-50 DeSabla Low Flow Reductions - WaterMax Scenario (Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Below Mountain Meadows Reservoir										16		
Bucks Lake to Lower Bucks Lake			12		12					16	16	12
Bucks Creek blw Lower Bucks Lake			12									
NFFR blw Rock Creek Dam											12	
NFFR blw Bucks Creek											12	12
NFFR abv Cresta Reservoir										40	60	28
NFFR blw Poe Dam										48	40	20

Source: northwest hydraulic consultants, inc.

Table 4.3-51 Drum Low Flow Reductions - PowerMax Scenario (Percentage Of Months With Flow Reductions Relative To Baseline)[1]

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Potter Valley												
Eel R blw Lake Pillsbury				8		4	4			16	28	20
Eel R blw Sand Creek										12	20	8
Drum-Spaulding												
N Yuba R abv Englebright Reservoir		20		16						28	16	20
M Yuba R blw Jackson Meadows Reservoir	16	24		12	28		12		20	16		12
Canyon Creek abv Bowman Lake		12					12		20	20		
S Yuba R blw Fordyce Lake										12	56	
S Yuba R abv confluence w/ M Yuba						20						
Yuba R blw Deer Creek											12	
Bear R abv Lake Combie										12	12	
Bear R blw Lake Combie										12		
Bear R blw Gold Hill/Combie Canal								12		16		

[1]Because the Eel River is 303(d) listed, the Potter Valley reaches indicate the percent of months with any low flow reductions. The remaining reaches show the percent of months with 20 percent or greater flow reductions.

Source: northwest hydraulic consultants, inc.

Table 4.3-52 Drum Low Flow Reductions - WaterMax Scenario (Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Drum-Spaulding												
N Yuba R abv Englebright Reservoir		20		16						16	12	16
M Yuba R blw Jackson Meadows Reservoir	20	24		12						28	16	16
Canyon Creek abv Bowman Lake		12								28		12
S Yuba R blw Fordyce Lake										12	32	
S Yuba R abv confluence w/ M Yuba						16	12	20				
Yuba R blw Deer Creek											16	
Bear R blw Rollins Reservoir										16	16	
Bear R abv Lake Combie									12	12	12	12
Bear R blw Lake Combie									12	12		
Bear R blw Gold Hill/Combie Canal						16		20	12	20		
Bear R blw Wolf Creek									12			
Bear R abv Camp Far West Reservoir									12			

Source: northwest hydraulic consultants, inc.

Table 4.3-53 Motherlode Low Flow Reductions - PowerMax Scenario
(Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mokelumne River												
Blue Lakes to Salt Springs Reservoir							12	16	16			
Twin and Meadow Lakes to Salt Springs Reservoir							32					
Upper Bear Reservoir to Lower Bear Reservoir									44	24	16	
Tiger Creek Conduit Bypass to NFMR		12				20	12				16	28
NFMR abv Bear River											16	28
NFMR abv Panther Creek											16	32
NFMR abv Tiger Creek Afterbay											20	32
NFMR blw Tiger Creek Afterbay											20	20
Mokelumne R abv Pardee Reservoir								12				
Stanislaus River												
MFSR abv Donnells Reservoir											16	
MFSR blw Beardsley Reservoir			12									
MFSR abv Sand Bar Diversion		20	20		24					16	20	
MFSR blw Sand Bar Diversion										16	24	
Stanislaus R blw NFSR										16	24	
SFSR blw Pinecrest Lake	12	20			16					20	24	
SFSR abv Lyons Reservoir	24	12		12			16		36	28	24	16

Source: northwest hydraulic consultants, inc.

mines, which will not be affected by the project. However, the project may result in reductions in flows on the NF Mokelumne River above Pardee Reservoir which could increase pollutant concentrations. Tables 4.3-53 and 4.3-54 indicate the percent of the months modeled in which flows would be below the identified threshold flow. Streamflow reductions in the Motherlode Regional Bundle could result in significant water quality impacts.

4.3.12.5 Impact 3-5: Evaluation of Impact to Kings Crane-Helms Regional Bundle (Significant)

Two reaches in the Kings Crane-Helms Region would experience significant streamflow reductions, as shown in Table 4.3-54 and Table 4.3-55 for the PowerMax and WaterMax Scenarios, respectively. None of the modeled reaches are in listed impaired watersheds, so the threshold for defining flow reductions was set as a 20 percent reduction relative to the baseline condition. Tables 4.3-48 and 4.3-49 indicate the percent of the months modeled in which the flows would be below the identified threshold flow. Streamflow reductions in the Kings Crane-Helms Regional Bundle could result in *significant* water quality impacts.

Table 4.3-54 Motherlode Low Flow Reductions - WaterMax Scenario
(Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mokelumne River												
Blue Lakes to Salt Springs Reservoir	12		16									
Upper Bear Reservoir to Lower Bear Reservoir									20	20		
Tiger Creek Conduit Bypass to NFMR						24			12		20	32
NFMR abv Bear River									12		20	32
NFMR abv Panther Creek								20		16	36	40
NFMR abv Tiger Creek Afterbay								20		16	36	40
NFMR blw Tiger Creek Afterbay											20	24
Mokelumne R abv Pardee Reservoir		12						12				
Stanislaus River												
MFSR abv Donnells Reservoir											16	
MFSR blw Beardsley Reservoir			12									
MFSR abv Sand Bar Diversion		20	20		24					28	24	
MFSR blw Sand Bar Diversion										16	32	
Stanislaus R blw NFSR										16	32	
SFSR blw Pinecrest Lake	32				12			16	28	64	36	52
SFSR abv Lyons Reservoir	28								28	20	12	32

Source: northwest hydraulic consultants, inc.

Table 4.3-55 Kings Crane-Helms Low Flow Reductions - PowerMax Scenario
(Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NF Willow Creek abv Manzanita Lake	92	76	52	60	60	64	88	84	84	96	84	68
SF Willow Creek abv SF Diversion	76	64	60	56	56	76	88	56	56	84	84	68

Source: northwest hydraulic consultants, inc.

4.3.12.6 Impact 3-5: Evaluation of Impact to Entire System

As documented above, flow data from the OASIS model was used to evaluate the potential project related impacts on low flows and water quality. The flows in each natural stream reach in the model were compared under the baseline and PowerMax and WaterMax Scenarios and any substantial flow reductions (greater than 20 percent) were identified in the preceding tables. The list of modeled reaches was also cross-referenced with the 303(d) list of impaired watersheds to identify existing water quality problems. In these reaches the criteria for evaluating significant flow reductions was assumed to be any reduction, no matter how small. The only reaches with low flow reductions which were also on the 303(d) list are in the in the Potter Valley Bundle. Based on the identified thresholds significant water quality impacts were identified in all five regional bundles. The specific reaches with flow reductions are listed in the tables above.

It should also be noted that the modeled baseline scenario assumes that reservoir releases to bypass reaches are made to just meet minimum instream flow requirements, wherever these exist. This is consistent with the fact that Pacific Gas and Electric Company, or a new owner, could operate in such a manner as to just meet these minimum flow targets, without violating their existing FERC licenses. However, as discussed in Section 4.3.3.1, historic flow data indicate that under current practice, Pacific Gas and Electric Company frequently releases more than the minimum required flow from its facilities to provide a “factor of safety” ensuring that minimum flow targets are not violated (SWRCB, 2000; Harrison, 2000). A more aggressive operator could choose to eliminate the safety factor and precisely meet minimum instream flow targets, thus reducing flows in many bypass reaches. Flow reductions of this sort would be in addition to the flow reductions discussed above. To the extent that these flow reductions occur in reaches with existing or potential water quality problems, the reductions would constitute a *significant* water quality impact.

4.3.12.7 Impact 3-5: Mitigation Measures

Mitigation Measures Identified as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-5: Prior to or concurrent with the transfer of title of any bundles upstream of the impacted stream reaches identified in Tables 4.3-48 through 4.3-56, the new owner shall, by binding written instrument, agree to maintain flows in the impacted reaches at or above the long term minimum monthly averages determined in the OASIS baseline modeling, to the extent that natural streamflows equal or exceed this level. The new owner shall have the option to establish, in consultation with the California State Water Resources Control Board, and in a manner satisfactory to the CPUC, alternative minimum allowable streamflows that would ensure protection of the identified beneficial uses, consistent with the governing Basin Plan.

4.3.12.8 Impact 3-5: Level of Significance After Mitigation

Less than significant.

Table 4.3-56 Kings Crane-Helms Low Flow Reductions - WaterMax Scenario (Percentage Of Months With Flow Reductions of 20 percent or More Relative To Baseline)

Reach	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NF Willow Creek abv Manzanita Lake	88	72	48	56	56	64	88	84	84	96	92	80
SF Willow Creek abv SF Diversion	76	64	56	56	56	76	88	56	56	84	92	80

Source: northwest hydraulic consultants, inc.

4.3.13 IMPACT 3-6: IMPACT, ANALYSIS, AND MITIGATION MEASURES

Impact 3-6: Project changes in reservoir operations and management could result in a significant impact on water quality inconsistent with the Basin Plan (*Significant*).

Changes in reservoir operations that result in lowering of water surfaces over all or part of the year increase the potential for adverse water quality effects. Lower water surface elevations can result in increased shoreline erosion as a result of exposure of steep, unvegetated bank areas and mobilization of delta sediments in the deltas of inflow streams. Reduced pool volumes can lead to increased water temperatures and increased concentrations of sediment and pollutants. These changes can also affect downstream water quality if lower quality water is released from the reservoirs.

The extent of reservoir water quality impacts is evaluated below for each regional bundle, using reduction in reservoir water surface elevation as an indicator of potential change. It is impossible to define a single criterion for reservoir water level changes that would realistically identify significant impacts at all reservoirs in the project. However, based on professional judgement, water level reductions of ten feet or more were defined as significant for purposes of this EIR. Water levels were assessed only for reservoirs with significant storage. Run-of-river facilities, by definition, do not have significant storage and as such, the project's ability to change operations is minimal. Reservoir water levels were examined for the baseline condition and PowerMax and WaterMax Scenarios for four water years (representative of critical, dry, normal, and wet conditions).

4.3.13.1 Impact 3-6: Shasta Regional Bundle

The Shasta Regional Bundle has three major storage reservoirs: Lake Britton, Lake McCloud, and Iron Canyon Reservoir. Note that only the PowerMax Scenario was modeled for this regional bundle since the WaterMax Scenario was determined to be infeasible. The OASIS modeling shows lower water levels in Lake Britton during most of the year, with water levels typically held 5 feet lower than baseline condition in all water year types. The only period during which Lake Britton water levels would be maintained at the same level as the baseline condition would be during the summer months. At Lake McCloud, the water levels under the PowerMax Scenario would be ten to 35 feet lower than baseline levels at various times of the year. The modeled variation in water levels occurs in different months depending on the type of water year being analyzed. Under the PowerMax Scenario, Iron Canyon Reservoir would experience water surface elevations up to 60-feet lower than the baseline in spring and up to 15 feet lower than baseline levels at other times in all types of water years.

All three reservoirs may experience significantly lower water levels in all types of water years under the modeled operational scenarios. This suggests a potential for *significant* water quality impacts in the Shasta Region.

4.3.13.2 Impact 3-6: DeSabla Regional Bundle

The DeSabla Region has three major storage reservoirs: Lake Almanor, Butt Valley Reservoir, and Bucks Lake. The PowerMax Scenario produces lower water levels throughout the year at Lake Almanor, with the exception of early summer in wet years. Water levels would be five to ten feet lower than baseline in all types of water years. At Butt Valley Reservoir, water levels would fluctuate widely under each of the modeled operations and there would be no pattern of differences under the PowerMax or WaterMax Scenarios. Bucks Lake would experience year-round reductions of up to 20 feet in each of the 4 water years analyzed under the PowerMax Scenario. Under the WaterMax Scenario, water levels would range from ten feet above to 20 feet below the baseline condition depending on the month and the water year type. Critical and normal years would show the most significant water level reductions.

Lake Almanor and Bucks Lake would experience significantly lower water levels in all types of water years under the modeled operational scenarios. This suggests that water quality impacts in the DeSabla Regional Bundle could be *significant*.

4.3.13.3 Impact 3-6: Drum Regional Bundle

The Drum Region has three major storage reservoirs: Lake Pillsbury, Lake Spaulding, and Jackson Meadows Reservoir (NID). Water levels in Lake Pillsbury would be reduced in the dry year under the PowerMax Scenario compared to the baseline. Simulated water levels in September and October 1981 would be reduced by as much as 30 feet compared to the baseline condition. Lake Spaulding water levels would not be affected to any great extent by the modeled operational changes except in dry years when water levels would be up to 30 feet lower than the baseline condition under both the PowerMax and WaterMax Scenarios. At Jackson Meadows Reservoir (NID), the fall-winter drawdown would be as much as 35 feet lower than baseline levels in the WaterMax Scenario in critical and wet years. The water level reduction is less pronounced in normal years and the dry year analyzed showed higher water levels throughout the year under both the PowerMax and WaterMax Scenarios.

Two of the three major reservoirs in this bundle would experience substantially lower water levels under the modeled operational scenarios. This suggests that water quality impacts in the Drum Regional Bundle could be *significant*.

4.3.13.4 Impact 3-6: Motherlode Regional Bundle

The Motherlode Regional Bundle has three major Pacific Gas and Electric Company storage reservoirs: Salt Springs Reservoir, Lower Bear Reservoir, and Strawberry (Pinecrest) Reservoir. Modeled water levels at Salt Springs Reservoir would be up to 75 feet lower than baseline during the analyzed dry year (1981) under the PowerMax Scenario. Simulated water surface elevations would typically be lower than baseline conditions through most of the year during dry, normal, and wet years while being the same or higher than baseline conditions during dry years. Under the WaterMax Scenario, modeled water surface elevations would typically be at or above the baseline conditions throughout the year. At Lower Bear Reservoir, storage under either the PowerMax or WaterMax Scenario would nearly always be at or above the baseline levels. Strawberry (Pinecrest) Reservoir would experience minimal or no reductions in water levels under the PowerMax Scenario. Under the WaterMax Scenario, water levels would typically be increased through most of the year.

Of the major storage facilities in this bundle, only the Salt Springs Reservoir would experience substantially lower water levels due to the modeled operational changes. However, considering the large deviations between the baseline and PowerMax conditions, potential water quality impacts in the Motherlode Regional Bundle are considered *significant*.

4.3.13.5 Impact 3-6: Kings Crane-Helms Regional Bundle

The Kings Crane-Helms Region has only one major storage reservoir with operational flexibility: Bass Lake. Both the PowerMax and WaterMax Scenarios produce lower water levels throughout the year at Bass Lake in both the critical and the normal year (1977 and 1989). Water levels in these years would be up to 35 feet below the baseline condition under the WaterMax Scenario and up to 30 feet below baseline in the PowerMax Scenario. In the analyzed dry year (1981), Bass Lake water levels were maintained similar to the baseline condition under the WaterMax Scenario while the PowerMax Scenario showed decreases of between ten and 25 feet compared to the baseline. In wet years, only minor reductions would occur and only in the fall, with a maximum difference of about five feet.

Bass Lake would experience substantially lower water levels during critical, dry, and normal water years under the modeled operational scenarios. This suggests that water quality impacts in the Kings Crane-Helms Regional Bundle would be *significant*.

4.3.13.6 Impact 3-6: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-6: Prior to or concurrent with the transfer of title for any reservoir, the new owner shall by binding written instrument agree to ensure substantial compliance with the relevant Basin Plan for the reservoir and downstream receiving waters.

4.3.13.7 Impact 3-6: Level of Significance After Mitigation

Less than significant.

4.3.14 Impact 3-7: Impact, Analysis, and Mitigation Measures

Impact 3-7: Project changes in timber harvest practices or extent could result in a significant impact on water quality inconsistent with the Basin Plan (*Significant*).

Logging has the potential to affect water quality by increasing pollutant loading or otherwise altering the characteristics of receiving waters. The primary silvicultural practices that contribute to water quality degradation include: timber harvest method and extent, road construction and maintenance activities, mechanical equipment operation, prescribed burning, and fertilizer and pesticide application. Water quality problems associated with these practices include: additional sediment runoff, added nutrient inputs, added chemical inputs (from pesticides, herbicides, insecticides, and fungicides), and temperature changes resulting from riparian vegetation removal.

As described in Chapter 4.2, one of the most significant potential changes in silvacultural practices resulting from the project would be a shift in timber harvest methods and extent. Pacific Gas and Electric Company's current timber harvest operations emphasize selective or uneven--aged harvest. This means harvesting selected trees in an uneven-aged stand either individually or in small groups at periodic intervals throughout a harvesting rotation. An alternative to selective harvest is clearcutting (or even-aged harvest). Clearcutting removes all merchantable trees from a specific area at the same time. This method is the most economical method of harvest. However, clearcutting also has the greatest potential for water quality impacts.

A new owner could become more aggressive and increase the amount of acreage under even-aged management. Without proper safeguards, this could increase pollutant loading to streams, resulting in significant water quality degradation. The extent of changes in timber harvest acreage and practices are shown in Tables 3-9 and 3-10 in Chapter 3. These tables were developed based on the assumptions documented in Chapter 3. As shown in Table 3-10, the total acreage harvested in all regional bundles under the aggressive harvest scenario is 4,038 acres per year, with 760 acres (19 percent) assumed to be even-aged harvest. Under the baseline conditions (Table 3-9), the annual harvest potential was estimated to be 2,040 acres with only 87 acres (four percent) in even-aged harvest.

On a systemwide scale there is very little potential for significant water quality impacts as a result of the assumed change in timber harvest methods. That is because relative to the overall size of the watersheds, the land area that might be subject to new or more aggressive harvest is miniscule. For example, in the Shasta Regional Bundle the increase in logged acres between 2002 and 2006 was estimated to be 2650 acres, 1785 acres of which was assumed to be even-aged harvest. The total harvest in this bundle under the aggressive harvest scenario was estimated to be 8,350 acres or approximately 0.2 percent of the total basin area of nearly four million acres in this regional bundle.

Irrespective of the lack of a basin wide impact on water quality, changes in harvest practices have the potential to cause localized impacts wherever logging occurs. Listed below are significance conclusions on a bundle by bundle basis. These conclusions were based on 1) the total projected harvest in the bundle under the aggressive harvest scenario compared to the baseline scenario (see Tables 3-9 and 3-10) and 2) the amount of potential even aged harvest in the bundle.

The prevailing assumption in the determination of impact significance is that Timber Harvest Plans (THPs) will be required as a precursor to any harvest. California Forest Practice Rules, which will be followed under a THP, govern erosion control and watershed and lake protection and are generally sufficient to mitigate significant impacts from timber harvesting.

4.3.14.1 Impact 3-7: Shasta Regional Bundle

In the Shasta Regional Bundle, anticipated timber harvest changes are as follows:

- Hat Creek Bundle: No increase in harvest. *No effect*
- Pit River Bundle: Modest increase in harvest including clearcutting. *Less than significant*.
- Kilarc-Cow Creek Bundle: Modest increase in harvest levels, including clearcutting. *Less than significant*
- Battle Creek Bundle: Modest increase in harvest in upper reaches of watershed. *Less than significant*

Overall effects on water quality in the Shasta Regional Bundle are expected to be *less than significant*.

4.3.14.2 Impact 3-7: DeSabla Regional Bundle

In the DeSabla Regional Bundle, anticipated timber harvest changes are as follows:

- Hamilton Branch Bundle: Minimal harvest. *No effect*.
- Upper North Fork Feather River Bundle: Modest increase in harvest at Lake Almanor and Butt Valley Reservoir. *Less than significant*.
- Bucks Creek Bundle: Modest increase in harvest near Bucks Lake *Less than significant*.
- Butte Creek Bundle: Modest increase in harvest at upper reaches of watershed. *Less than significant*.

Overall effects of timber harvesting on water quality in the DeSabla Regional Bundle are *less than significant*.

4.3.14.3 Impact 3-7: Drum Regional Bundle

In the Drum Regional Bundle, anticipated timber harvest changes are as follows:

- North Yuba River Bundle: No harvest. *No effect*.
- Potter Valley Bundle: Significant increase in harvest. The Eel River watershed is listed as impaired for sedimentation and siltation. Any increase in sediment could cause a significant impact. The EPA will be developing a TMDL for this watershed, but the prioritization is low and the TMDL is not expected until 2011. S*ignificant*.
- South Yuba River Bundle: Significant increase in timber harvest including clearcutting. S*ignificant*.
- Chili Bar Bundle: No harvest. *No effect*.

Overall, effects of timber harvesting on water quality in the Drum Regional Bundle are *significant*.

4.3.14.4 Impact 3-7: Motherlode Regional Bundle

In the Motherlode Regional Bundle, anticipated timber harvest changes are as follows:

- Mokelumne River Bundle: Modest increase in harvest. *Less than significant*.
- Stanislaus River Bundle: Modest Increase in harvest. *Less than significant*.
- Merced River Bundle: No harvest. *No effect*.

Overall, effects of timber harvesting on water quality in the Motherlode Regional Bundle are *less than significant*.

4.3.14.5 Impact 3-7: Kings Crane-Helms Regional Bundle

In the Kings Crane-Helms Regional Bundle, anticipated timber harvest changes are as follows:

- Crane Valley Bundle: Negligible increase in harvest. *Less than significant*.
- Kerckhoff Bundle: No harvest. *No effect*.
- Kings River Bundle: Negligible increase in harvest. *Less than significant*
- Tule River Bundle: No harvest. *No effect*.
- Kern Canyon Bundle: No harvest. *No effect*.

Overall, effects of timber harvesting on water quality in the Kings Crane-Helms Regional Bundle are *less than significant*.

4.3.14.6 Impact 3-7: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-7: Specific mitigations contained in the California Forest Practice Rules that should be applied to logging on current Pacific Gas and Electric Company lands include:

- Restrictions on cutting trees and use of equipment adjacent to watercourses
- Restrictions on winter operations.
- Requirements for installing and spacing of waterbreaks on skid trails and roads
- Restrictions on the construction and removal of watercourse crossings
- Restrictions on the type of logging equipment that can be used on steep slopes and erosion hazard areas

Any THP for proposed harvest in the 303(d) listed Eel River watershed shall address existing sediment sources as condition of approval.

4.3.14.7 Impact 3-7: Level of Significance After Mitigation

Less than significant.

4.3.15 Impact 3-8: Impact, Analysis, and Mitigation Measures

Impact 3-8: Construction activities associated with development of Project Lands would involve earthmoving activities that could affect receiving water quality through increased sedimentation (*Less than Significant*).

4.3.15.1 Impact 3-8: Evaluation of Impact to Entire System

The assumptions described in Chapter 3 indicate the project could result in increased development on Project Lands within each of the five regional bundles. Of the five regional bundles, the Motherlode Regional Bundle is assumed to have the least development (319 EDUs), and the Drum Regional Bundle is assumed to have the most (4,071 EDUs). However, because development of Project Lands is assumed to occur in all five regional bundles, and because of the regulatory framework in place to regulate such operations (which apply throughout the five bundles), this impact is discussed at the system-wide level. It is not any more or less likely that the significance level of water quality impacts resulting from development of Project Lands would be greater in one regional bundle than another, although the magnitude of the effect would vary depending on the acreage disturbed and the construction techniques used.

Construction activities would involve earthmoving activities (e.g., trenching, excavation, grading, and contouring) that could expose soil to erosion at an accelerated rate during storm events. Sediment from erosion can have both short-and long-term effects on water quality. Short-term effects can include increased turbidity, which could result in adverse impacts on fish and wildlife habitat, reduced water pump life due to abrasion, and impaired recreation and aesthetic value. Long-term effects can include increased flooding hazard from reduced channel capacities, increased irrigation system maintenance, and increased dredging costs. Sediments can also carry other pollutants such as pesticides and heavy metals from adjacent agricultural or urban land uses. As a result, construction activities associated with Project Lands development could introduce new contaminants to surface water or exacerbate existing surface water and/or groundwater quality conditions.

Construction on Project Lands would be subject to numerous Federal, State, and local laws and regulations that address water quality protection, including the Clean Water Act, the State Porter-Cologne Water Quality Control Act, and their implementing regulations at the State level. Implementation of these regulations would ensure that water quality would not be degraded below the established standards, and are closely monitored by the Regional Water Quality Control Boards and the Department of Water Resources.

As noted in the environmental setting, storm water runoff from construction sites requires coverage under a general NPDES permit. A new permit, which revised and updated the 1991 General Construction Activity Storm Water Permit, was issued by the SWRCB in August 1999. This permit generally applies to sites larger than five acres in size. Construction on sites one to five acres in size are regulated under the Phase II program. Landowners are responsible for obtaining and complying with the permits that may delegate specific duties to developers and contractors by mutual consent. Permit applicants are required to prepare and retain at the construction site a storm water pollution prevention plan that describes: the site erosion and sediment controls, means of waste disposal, implementation of approved local plans, control of post-construction sediment, erosion control measures and maintenance responsibilities, and non-storm water management controls. Dischargers are also required to inspect their construction sites before and after storms to identify storm water discharge associated with construction activity and to identify and implement controls where necessary.

Compliance with construction activity permit requirements would control the amount and type of discharge into surface waters from construction activities, thus maintaining existing surface water quality. Compliance with the General Construction Activity Storm Water Permit would minimize degradation of water quality from construction activities. Therefore, this impact is *less than significant* for the entire system.

4.3.15.2 Impact 3-8: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

Mitigation Measure 3-8: Obtain and comply with the requirements of the General Construction Activity Stormwater Permit.

Mitigation Measures Identified in This Report

None proposed.

4.3.15.3 Impact 3-8: Level of Significance After Mitigation

Less than significant.

4.3.16 IMPACT 3-9: IMPACTS, ANALYSIS, AND MITIGATION MEASURES

Impact 3-9: The project could result in land development that could affect water quality through increases in urban pollutants in stormwater runoff and septic system use (*Significant*).

4.3.16.1 Impact 3-9: Evaluation of Impact to Entire System

The land development assumptions in Chapter 3 indicate that residential, commercial, or recreational development could occur in all five regional bundles, although the type and intensity of development would likely vary within each individual bundle.

Conversion of undeveloped land to urban uses, which would increase the amount of impervious surfaces, would alter the types and levels of pollutants that could be present in runoff by increasing the rate and volume of stormwater runoff. With the exception of Coal Canyon (see Section 4.11, Public Services and Utilities), it is assumed that new development would be served by septic systems, based on information provided by county staff. Recreational facilities may be used or managed differently under a new owner. All of these conditions have the potential to adversely affect water quality, resulting in a significant effect regardless of location. Therefore, this impact is discussed at the system-wide level. Sources of potential impacts and current management methods are described below.

Urban Runoff

Runoff from undeveloped Project Lands contain high concentrations of sediment because the sites are largely undeveloped. Small amounts of nutrients, naturally occurring metals and minerals, pesticides, and organic matter may also be present in runoff from undeveloped areas. Urban runoff studies throughout the U.S. have shown that the concentration of suspended solids usually decreases as exposed soils are covered by impervious surfaces, although some particulates may still be present due to entrained dust on roadways and parking lots and in runoff from any remaining open space areas. Activities that could increase the types or quantities of pollutants in runoff due to development include motor vehicle operations, residential maintenance, littering, careless material storage and handling, domestic animal and wildlife wastes, and pavement wear. Pollutants typically associated with urban uses, such as those that could be developed as a result of the project, include oil and grease, coliform bacteria, biochemical oxygen demand (BOD), chemical oxygen demand (COD), total organic carbon (TOC), total petroleum hydrocarbons (TPH), nitrogen, phosphorus, heavy metals such as lead, copper, and zinc, and suspended solids. Pesticides, herbicides, and other landscape maintenance products typically used in residential, commercial, or recreational developments could also be present in runoff.

It would be speculative to identify specific post-development water quality impacts that could occur. However, it is conservatively assumed for purposes of the evaluation in this EIR, that new or additional stormwater runoff generated by the project would to contain some level of contaminants typically associated with urban development. Because Project Lands that could be developed are situated in rural areas not served by conventional separate storm sewer or combined sanitary/storm drainage systems, it is further assumed stormwater runoff generated by both low-intensity (e.g., recreational facilities) and high-intensity (e.g., residential subdivision) development would ultimately be discharged to nearby surface water via existing natural drainage courses or engineered culverts, channels, or swales created as part of the development.

Minimizing adverse effects on surface water quality as a result in increased urban development in rural areas has been identified in many jurisdictions as a watershed management objective. The quality of urban runoff can be effectively managed through the use of Best Management Practices (BMPs). Structural BMPs could include engineered features that provide some treatment, such as vegetative drainage ways, detention infiltration ponds or filtration basins, or filters at drop inlets. Non-structural BMPs are typically non-engineered management measures such as administrative and education programs focused on pollution prevention and source control. The selected BMPs should be based on the type of development and land uses at the particular locations, taking into account local and regional drainage and water quality considerations. The use of BMPs is required under Federal and State NPDES program requirements for certain jurisdictions (urban areas) or types of activities meeting certain criteria; however, all of the Project Lands assumed for development are located in non-urban, unincorporated county areas where comprehensive urban runoff water quality programs may not exist, are still being developed or have not been fully implemented to date, or may not yet be required under Federal or State programs. (As noted in Section 4.3.2, Stormwater Runoff Water Quality Protection, for example, Shasta, Butte, Yuba, Merced, Stanislaus, and Tulare counties only recently became designated under the NPDES Phase II program; however, programs implementing the MS4 requirements in these counties may take several years to be developed). Consequently, without proper runoff management and mechanisms for enforceability, the potential increase in urban contaminants attributable to new development that could occur with the project could degrade water quality or interfere with achieving Basin Plan water quality objectives. This is considered a significant impact for all five bundles. The magnitude of this effect would vary, however, within each individual bundle, depending on the intensity and type of development and local water quality concerns. In some cases, urban runoff, combined with existing water quality problems (Pit River above the confluence of Fall River, for example), could exacerbate the problem.

Septic System and Alternative Wastewater System Use

Land development could also increase the number of individual septic systems or alternative wastewater disposal systems in communities not served by developed wastewater collection and treatment systems. Septic system use has also been identified as a potential source of surface water contamination in many of the rural watersheds where most Project Lands are situated. Because individual septic systems provide only primary treatment of effluent, the discharged water can contain elevated levels of chemical constituents. Improperly sited (e.g., proximity relative to surface water) or poorly functioning septic systems (e.g., soils that do not provide effective leaching or percolation) can result in increased nitrate levels in groundwater, which is the most common result of domestic septic system use. Some groundwater may eventually be discharged to local waterways via subsurface migration. The extent to which surface water or groundwater quality could be affected by septic or alternative wastewater system use would depend on underlying soil characteristics (e.g., permeability) and the amount and rate of wastewater discharged to the septic system.

In addition to increased septic system use, changes in recreation use patterns or sanitary facility maintenance activities at reservoirs or campgrounds along stream reaches as a result of new ownership could also affect water quality, primarily by altering bacteria and nitrate concentrations. Therefore, potential water quality effects as a result of the project would be considered significant because they could degrade water quality or interfere with achieving Basin Plan water quality objectives.

4.3.16.2 Impact 3-9: Mitigation Measures

Mitigation Measures Proposed as Part of Project

Mitigation Measure 3-9: Developers would be required to implement applicable requirements and standards established under the Federal and State NPDES urban stormwater runoff water quality programs where such regulations are implemented by the local jurisdiction. In addition, they would be required to install and operate septic systems and alternative wastewater systems in accordance with local requirements.

Mitigation Measures Identified In This Report

Mitigation Measure 3-9a: Where NDPES stormwater management programs developed in accordance with current regulations have not been established by the jurisdiction with land development approval authority, or where the intensity or location of land development is determined by the local approving authority to present minimal threat to water quality, prior approval of new land use development projects, the applicant shall consult with the local planning authority to identify appropriate urban stormwater runoff Best Management Practices (BMPs) to be incorporated into project design to manage the quality of runoff from the proposed development. BMPs that may be used could include, but would not be limited to, those described in the California Stormwater Management Task Force Best Management Practices Handbook, the Bay Area Stormwater Management Agencies Associates (BASMAA) Design Guidance Manual, or other recommendations of the local jurisdiction. Monitoring of the effectiveness of stormwater quality controls shall be implemented as directed by the local approving authority.

Mitigation Measure 3-9b: Where local jurisdictions have identified the need for improved septic and alternative wastewater system installation, monitoring, inspection, or siting requirements to minimize further water quality degradation, prior to approval of land use changes, the new owner or its successor-in-interest shall consult with the local jurisdiction during initial project design to identify the appropriate wastewater system design features, taking into account local hydrogeologic and soils conditions. If site-specific soils or hydrogeologic conditions cannot support adequate septic or alternative wastewater systems, other methods of wastewater collection, conveyance, and treatment shall be identified and used.

Alternate Mitigation Measure 3-9c*:* Prior to or concurrent with the transfer of title for any bundle, there shall be recorded against the Project Lands within the bundle, conservation easements running with the land (in a form and substance approved by the CPUC) precluding any further land use development on such Project Lands.

4.3.16.3 Impact 3-9: Level of Significance After Mitigation

Implementation of Mitigation Measures 3-9a and 3-9b would result in the impact being *less than significant*. Implementation instead of Alternative Mitigation Measure 3-9c would eliminate the significant impact altogether.

4.3.17 IMPACT 3-10: IMPACTS, ANALYSIS, AND MITIGATION MEASURES

Impact 3-10: The project could result in changes in reservoir sediment management practices which could result in a significant impact on water quality, inconsistent with the Basin Plan (*Significant*).

4.3.17.1 Impact 3-10: Evaluation of Impact to Entire System

Reservoirs are, by their nature, sediment traps. Sedimentation is an ongoing natural process that cannot be stopped. The process can only be slowed and the problems mitigated to an acceptable level of impact upon hydroelectric facilities and downstream receiving waters. The accumulation of sediment in a reservoir reduces usable storage capacity, degrades water quality, obstructs water diversion structures and dam outlets, and interferes with hydroelectric operations, flood control, and other beneficial uses. When sediment problems become pressing and reservoir functions are impacted, costly remedial actions are often necessary. Thus, reservoir sediment management is prudent before sediment problems become critical. Detailed sedimentation studies are often necessary to scope the sediment problems, identify the sediment sources, and develop an effective management plan. Any management plan adopted must also satisfy environmental, regulatory, and economic concerns.

There are a number of environmental problems associated with reservoir sedimentation and remediation actions. As noted above, the accumulation of sediments in a reservoir can reduce the beneficial functions of a reservoir, including the maintenance of water quality. Reservoir sediment deposits may become re-suspended to cause turbidity during times of the year when the water would normally be clear. Generally, the turbidity and suspended material concentration from such re-suspension is far less than what occurs naturally during high flows. However, some aquatic species may be affected by high sediment concentrations at times of the year when normal sediment concentrations are low. Sediment deposited in reservoirs may also contain toxic materials such as mine tailings. Toxic sediments, if disturbed, may contaminate the water column. Toxic sediments can also present a disposal problem if dredged.

Even though sediment is a natural constituent of stream systems and necessary for the life cycle of many species, the California Department of Fish and Game, the Regional Water Quality Control Boards, and Federal environmental agencies (NMFS, USF&WS, EPA) in the past have considered sediment discharged from reservoirs to be a pollutant and deleterious to the environment. Agency opinion is generally that once sediment is trapped in a reservoir, it is the problem of the reservoir owner to manage, subject to the regulation of the environmental agencies (Harrison, 2000).

Flushing or sluicing of large quantities of sediments from a reservoir can result in downstream water quality degradation and is not generally an acceptable solution, although it has been approved for small diversion reservoirs in a few cases under strict regulation (Harrison, 1996). Flushing or sluicing with inadequate auxiliary flows to carry sediments through the system may be environmentally damaging due to deposition in the streambed. Sluicing and flushing are, by their nature, more efficient at scouring fine-grained materials from the reservoir than in moving spawning gravels. High concentrations of fine sediments released during low-flow periods may result in substantial downstream deposition, plugging gravels and smothering biota.

A compounding problem occurs when insufficient volumes of sediments have been released over time to maintain stable channel conditions downstream of a reservoir. Long term sediment interception can have two significant impacts. First, the streambed downstream of the dam may degrade as bed materials are removed faster than they are replaced by sediment input from tributaries and upstream sources. Second, gravels of suitable size for fish spawning downstream of dams can become depleted over time.

Annual operability checks, including the opening of low level outlets at most dams, are required by the FERC licenses and the California Division of Safety of Dams (DSOD). The initial operation of the low level outlets generally results in the discharge of turbid water, as recent sediment deposits in the vicinity of the inlet are entrained into the flow. Typically, CDF&G has required that dilution flows of clear water be simultaneously released from other dam outlets and that follow-up flushing flows be released to ensure the sediment is dispersed downstream. The Pacific Gas and Electric Company and CDF&G have in the past documented agreements on such dilution and flushing flows with an exchange of letters.

The physical processes of reservoir sedimentation and remediation and the associated environmental effects are complex. The laws and regulations applicable to sediment management, dredging, and disposal of sediment are also complex. Development of a sediment management plan for a reservoir requires adequate hydraulic engineering and environmental analyses to understand the interaction of physical processes, to ensure the plan will function as intended, and to satisfy regulatory agencies. Sediment management is often a contentious issue. The SWRCB has expressed concern that a new owner may not have the same sophistication, resources, or level of concern as Pacific Gas and Electric Company for managing sediment in project reservoirs. The State and Pacific Gas and Electric Company have a long history of working together to address this issue and coming to mutual agreements with regard to sediment management policies and practices. The State is concerned that a new owner may be unaware of the complexity of sediment management and may be more difficult to deal with to prevent adverse water quality impacts (SWRCB, 2000). These impacts are considered *significant*.

4.3.17.2 Impact 3-10: Mitigation Measures

Mitigation Measures Proposed as Part of the Project

None.

Mitigation Measures Identified in This Report

Mitigation Measure 3-10: Pacific Gas and Electric Company shall document all existing reservoir sediment management practices at Company facilities including information about the frequency, timing, and extent of current practices, the relevant regulations governing sediment management, and the history of past water quality problems resulting from sediment management at Company facilities. Prior to or concurrent with the transfer of title for any bundle, new owners shall, by binding written instrument, agree to become familiar with existing sediment management practices of the Company and to develop and enact sediment management plans to prevent significant water quality impacts within and downstream of all facilities.

4.3.17.3 Impact 3-10: Level of Significance After Mitigation

Less than significant.

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