EXHIBIT H—PLANS AND ABILITY OF APPLICANT TO OPERATE PROJECT EFFICIENTLY

Klamath Hydroelectric Project
(FERC Project No. 2082)

PacifiCorp
Portland, Oregon

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H1.0 INTRODUCTION

H1.1 COMPANY BACKGROUND

PacifiCorp owns and operates 53 hydroelectric plants and serves as operator for two additional plants. These facilities are located throughout the states of Oregon, Washington, California, Idaho, Utah, and Montana. The facilities contain a total of 91 turbine generator units, which represent an installed capacity of approximately 1,100 megawatts (MW), or about 12.8 percent of PacifiCorp's current total generating capacity.

Approximately 190 full-time employees are required to operate, maintain, and provide support for these hydroelectric generation facilities. This group, which is called the Hydro Resources Department, includes 105 operations and maintenance personnel located at various project sites, as well as 54 management, engineering, and administrative support staff located in Portland, Oregon, Salt Lake City, Utah, and various field locations.

Operational responsibilities are shared among three different workforces within PacifiCorp. The Wholesale Energy Services (WES) group is responsible for scheduling the various project generations while providing water management to meet Federal Energy Regulatory Commission (FERC) license articles, agency needs, and public needs. WES forecasts for storm events, snowpack, and runoff and it determines how these factors impact water management. WES provides a daily schedule to the field operation groups for hydroproject power generation and water releases. While generating facilities are not staffed 24 hours per day, 7 days a week, they are still monitored around the clock. PacifiCorp's Hydro Control Center (HCC), located near Ariel, Washington, is responsible for monitoring all the facilities and controlling specific power plants that are crucial for generation needs and water releases. The response team for any issue needing onsite attention is made up of the various field personnel stationed at or near the project facilities.

PacifiCorp's Power Operations Department assists the Hydro Resources Department with maintenance of many of the generation facilities, including the Klamath Hydroelectric Project (Project). The Power Operations Department primarily maintains substations and related equipment and provides many of the electrical maintenance services required by the Project. For the Project, these personnel are located in Medford, Oregon, and are within 1 to 2 hours of Project developments.

All Hydro Resources Department personnel are required to attend regular safety and training programs. Staff located at the Project attend monthly safety and training meetings. Off-Project staff located in the Medford and Portland offices attend regular safety meetings. In addition, staff refresh their skills by attending additional training courses provided by PacifiCorp (see Section H7.2 of this exhibit for additional information on the company's safety program).

H1.2 PROJECT OVERVIEW

The existing Project consists of seven mainstem hydroelectric developments on the Upper Klamath River and one tributary hydroelectric development on Fall Creek. PacifiCorp owns and operates the Project under a single license issued in 1956 by FERC. On March 1, 1956, FERC issued California Oregon Power Company (COPCO), the Project owner at the time, a single FERC license that includes all eight hydroelectric developments. The 50-year license contains requirements that define and regulate Project operations (FPC 1956). Within the license, a set of 63 standard and special conditions are now set forth as requirements. The existing FERC license (Project No. 2082) expires on March 1, 2006.

The Project is located on the Upper Klamath River in Klamath County, south-central Oregon, and Siskiyou County, north-central California. The nearest principal cities are Klamath Falls, Oregon, located at the northern end of the Project area, Medford, Oregon, 45 miles northwest of the downstream end of the Project, and Yreka, California, 20 miles southwest of the downstream end.

The existing Project consists of six generating developments along the mainstem of the upper Klamath River, between river mile (RM) 190 and RM 254, a reregulation dam with no generation facilities, and one generating facility on Fall Creek, a tributary to the Klamath River at about RM 196.

Link River dam and the associated East Side (3.2 MW) and West Side (0.6 MW) powerhouses are the most upstream developments, located near RM 254 within the city limits of Klamath Falls, Oregon. The U.S. Bureau of Reclamation (USBR) owns the Link River dam and PacifiCorp operates it under USBR's directive. Therefore the dam is not considered part of the licensed Project. The dam was built to supply water to both USBR's Klamath Irrigation Project and PacifiCorp's Klamath Hydroelectric Project. East Side and West Side powerhouses and associated waterways are part of the FERC Project. Keno dam, a reregulating facility with no generation capability, is the next facility, 20 miles downstream at RM 233. Keno reservoir buffers inflow and outflow of USBR's Irrigation Project.

For the future Project, as proposed in this license application, PacifiCorp plans to remove the East Side and West Side developments from service. PacifiCorp also proposes to exclude the Keno Development from the relicensed Project because the development is no longer subject to FERC jurisdiction. In the original license, FERC exercised jurisdiction over the Keno Development because it was anticipated that the development would include generation (see Pacific Power & Light Co., 34 FPC 1387 [1965]). However, PacifiCorp has not installed generation at the development and has no plans to do so. Moreover, PacifiCorp's operation of the Keno Development does not substantially benefit generation at PacifiCorp's downstream Project developments. As a result, there is no longer any basis upon which to conclude that the Keno Development is subject to FERC jurisdiction.

The J.C. Boyle development (80 MW) is located downstream of Keno and is the most upstream Project development under the proposed, modified Project. The dam is at RM 224.7 and the powerhouse is several miles downstream at RM 220.4. As the river continues into California, it enters Copco reservoir, which supplies Copco No. 1 (20 MW) and No. 2 (27 MW) hydroelectric facilities, at RM 198.6 and RM 196.8, respectively. The Iron Gate development (18 MW) is farthest downstream at RM 190. Fall Creek, a tributary, flows through a small powerhouse (2.2 MW) and then into the upper end of Iron Gate reservoir.

The existing Project is located on private and public properties. Public properties include a portion of Keno dam that resides on USBR-managed land and the J.C. Boyle waterway and powerhouse, which is on BLM-managed land. There are two Federal Wild and Scenic reaches: one in the Project reach just downstream of J.C. Boyle powerhouse extending to the Oregon-California state line, the other downstream of Iron Gate dam. The proposed FERC license Project boundary, which extends from J.C. Boyle reservoir to Iron Gate dam, encompasses approximately 3,737 acres. Of this area, 156 acres are United States-owned land managed by the U.S. Bureau of Land Management (BLM).

PacifiCorp's operation of electrical systems (including the operation of the Project) is coordinated using guidelines prescribed by the regions' Northwest Power Pool (NWPP). PacifiCorp provides generation to the Northwest Power Grid following these NWPP guidelines.

H1.3 PROJECT EFFICIENT AND RELIABLE ELECTRICAL SERVICE

While PacifiCorp has no plans to increase Project capacity or generation other than through normal generation maintenance, it does plan to reduce generation with the decommissioning of the East Side and West Side developments (a total of 3.8 MW). To provide efficient and reliable electrical service to company customers, the company will continue to closely coordinate Project operation with other projects and with the electrical system as a whole.

Operation of the Project as a whole, or as individual developments, is closely linked to USBR's Klamath Irrigation Project, located upstream of the Klamath Hydroelectric Project. The Klamath Irrigation Project significantly controls the amount of water released into the hydroelectric project. USBR's need to meet Endangered Species Act (ESA) requirements, both within Upper Klamath Lake and downstream of Iron Gate dam, together with irrigation demands, affect PacifiCorp's ability to generate electricity at its hydroelectric developments. Consequently, PacifiCorp's scheduling of Project reservoir storage and releases is primarily controlled by USBR's water management. It is important to note that all water management activities in Upper Klamath Lake are conducted independently of the hydroelectric Project operations downstream. PacifiCorp has little storage flexibility in its hydro system operation (11,749 acre-feet [AF] total in three reservoirs). As such, powerhouse operations are dependent on Klamath River flows needed to address ESA requirements as directed in recent Biological Opinions (BOs) (an obligation of USBR) or the availability of extra tributary spring water. These ESA-related flow requirements and their derivation are described in Exhibit B of the final license application.

Although no longer proposed to be a part of the Project, it should be noted that the Keno reservoir located just downstream of Upper Klamath Lake has 91 water diversion points off the reservoir. These diversion points include both federal and private facilities, most of which are used for crop irrigation, but a few supply water to wildlife refuges. Although the water in the Klamath Basin has not been completely adjudicated, claims for water withdrawal from Keno reservoir include approximately 7,690 cubic feet per second (cfs) and 186,174 AF for USBR and U.S. Fish and Wildlife Service (USFWS) use, and approximately 750 cfs and 13,143 AF for private and irrigation district water (OWRD, 2002). The maximum irrigation demand usually occurs in late July and totals about 34,000 AF during an average year.

During the nonirrigation season, PacifiCorp has more flexibility in the operation of its Klamath Project. However, low flows out of Upper Klamath Lake limit the ability to generate large amounts of continuous electricity or to provide extensive peaking capability to meet system energy demands. Typically, once the irrigation season ends, all available flow from Upper Klamath Lake tributaries is stored in the lake and released for irrigation purposes the next irrigation season. During the nonirrigation season, the only water available to the hydroelectric Project is a combination of the inflow below Upper Klamath Lake and a released flow that together meet the downstream ESA requirement. This again emphasizes that USBR's operation of the Klamath River system gives the highest priority to meeting ESA requirements and irrigation demands, with hydroelectric power production a lower priority.

PacifiCorp also closely coordinates the Project operation with local and regional electrical systems. The operation of electrical systems is coordinated through PacifiCorp's Hydro Control Center in Ariel, Washington. Although the Project is connected to the western grid and is available for delivery throughout the west, power generated at the Project is generally used to serve PacifiCorp's customers in southern Oregon and northern California.

H1.4 FINANCIAL RESOURCES

PacifiCorp's sources of financing and annual revenues are adequate to meet the continuing operation and maintenance needs of the Project. PacifiCorp is a utility with broad experience in the construction, operation, and maintenance of hydroelectric projects. The consolidated balance sheet from PacifiCorp's 2002 Annual Report is available in FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others.

H2.0 NEED FOR PROJECT ELECTRIC GENERATION

H2.1 PACIFICORP'S INTEGRATED RESOURCE PLANNING PROCESS

On a periodic basis, PacifiCorp completes a comprehensive analysis of future load growth, the ability of existing power plants to meet customers' electric energy service needs, and the need for new resources, including new power plants and customer energy efficiency programs. This process, referred to as the Integrated Resource Plan (IRP), provides a framework for the prudent future actions required to ensure that PacifiCorp continues providing reliable and least-cost electric service to its customers. Recently, more than 30 stakeholders, representing regulatory commissions, environmental agencies, consumer interests, and others, contributed significant and valuable input to a plan that analyzed load growth, potential resource options, and costs and risks associated with meeting energy needs. The 2003 IRP was submitted to state regulatory agencies in January 2003, requesting that they acknowledge and support its conclusions, including the proposed action plan. The states with regulatory requirement to file an IRP (Oregon, Washington, Idaho, and Utah) acknowledged the plan in 2003.

The planning and decisionmaking associated with meeting load requirements in both short-term and long-term time horizons are a function of PacifiCorp's Commercial and Trading Organization (C&T). This organization strives to:

- Deliver the most economic solution for both the customer and PacifiCorp
- Reduce commodity risk in the regulated business
- Serve load with both owned assets and purchases
- Reduce cost and risk with hedges and load management programs

The IRP is developed by C&T personnel and is an integral component of the ongoing business and strategic planning of PacifiCorp. Changes in the structure and regulation of the electricity industry require changes in the approach PacifiCorp takes to integrated resource planning. Given the potential for commodity markets (both gas and electric) to exhibit rapid price swings (volatility), alternative resource plans must be evaluated in terms of their exposure to price volatility, in addition to their long-run average costs. Furthermore, unpredictability in the future costs of new supply alternatives arising from gas price and emissions cost uncertainties must be recognized. Finally, the rapidly evolving structure of markets and their attendant risks demand a more timely and responsive process for keeping resource plans current. The 2003 IRP plan represents PacifiCorp's efforts to adapt its resource planning to these new requirements.

The IRP found that a significant amount of additional resources will be needed to meet the energy demands of customers in PacifiCorp's six-state service area. A projected load growth rate of 2.2 percent per year on the company's East system (Utah, Wyoming, and Idaho) and 2 percent per year on the West system (Oregon, Washington, and California) indicates a need for about 4,000 additional MW of capacity between 2004 and 2014. This growth includes additional energy needs of current customers, requirements for new customers, and potential increased requirements for supply reserves. The total needs would increase the company's energy resource portfolio by about 40 percent of current levels, including long-term purchases, by 2014. In addition, the IRP considers lost capacity resulting from aging plants, reduced output, and expiring supply contracts. For example, the IRP includes the perspective that the East Side and West Side developments would be decommissioned in 2006. PacifiCorp's resource needs are focused on meeting the requirements of its retail customers.

PacifiCorp's integrated resource planning methodology uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets. This methodology provides an examination of both the expected future costs and the risks of future outcomes. It also allows an examination of the tradeoff between cost and risk inherent in resource planning choices. This is in contrast to PacifiCorp's recent IRPs, in which a point-estimate optimization method was used to develop plans tuned to a few specific, future cases. The IRP also emphasizes portfolios of resources, because a diverse portfolio is a well-known means of managing risks.

The starting point for the analysis is the determination of the gap between growing loads and existing resources, as discussed above. From this starting point, the analysis involves a number of distinct steps:

1. **Portfolio Development**: The first step is the formulation of resource portfolios. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios were chosen to span a complete range of likely resource strategies.

2. **Operational Simulation**: Next, the operation of each portfolio is simulated. The simulation develops a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.

3. **Cost Analysis**: Each portfolio's system operating costs are combined with the corresponding capital costs, yielding the Present Value of the Revenue Requirement (PVRR), the main cost metric.

4. **Screening**: Performance measures (PVRR and others) are used to screen the portfolios. Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.

5. **Risk Analysis and Stress Testing**: The risk analysis simulates the performance of a portfolio under a large number of possible futures. The risk analysis also allows conclusions to be drawn regarding each portfolio's sensitivities to assumptions about the future and assessments to be made regarding the variability in a portfolio's cost.

6. **Portfolio Refinement**: Based on these results, iterative improvements to the best performing portfolios are made, defining hybrid portfolios that are tested against each other to identify the least-cost, risk-adjusted portfolio.

Modeling was performed on a system basis. Although the transfers between the East and West systems were measured and reported, state-specific impacts were not assessed. It is expected that these issues will be addressed in detail following the conclusion of the multistate process (MSP) discussions.

The IRP includes an action plan that focuses on the next 10 years. Components of the action plan are as follows:

- Detailed plan, including specific findings of need and implementation actions
- Decision processes for implementing the action plan
- Procurement program for implementing the action plan
- Update on PacifiCorp's current procurement and hedging strategy
- Description of how PacifiCorp resource planning and business planning are aligned
- Discussion on the action plan's consistency with Oregon's restructuring legislation (SB-1149)

The action plan is further summarized below.

H2.1.1 Action Plan

The action plan aims to ensure that PacifiCorp will continue meeting its obligation to serve customers at a low cost with manageable and reasonable risk. At the same time, the Plan remains adaptable to changing course, as uncertainties evolve or are resolved, or if a paradigm shift occurs. An element of the action plan is to preserve PacifiCorp's optionality and flexibility in the future.

The action plan is based on the best information available at the time the IRP is filed. It will be implemented as described, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the action plan no less frequently than annually. Any refreshed action plan will be submitted to the State Commissions for their information. The action plan will also be revised as a consequence of subsequent IRPs.

PacifiCorp's action plan applies a diversified resource approach addressing energy use reduction from both demand-side and supply-side (new resources) management. The Diversified Portfolio I includes:

- Up to 450 average MW of demand-side management (DSM) programs

- 1,400 MW of renewable energy

- 2,100 MW of new base-load energy—large, efficient generation that operates continuously

- 1,200 MW of peaking resources—generation that can quickly meet energy needs during highest-use periods, typically during periods of extreme heat or cold

- 700 MW of shaped resources—contracts or resources that fill specific needs

PacifiCorp's DSM programs are described in Section H2.2. The remaining parts of the Diversified Portfolio I are described in Sections H2.1.2 through H2.1.5.

H2.1.2 Renewables

The beginning portfolios that were developed in the IRP contained wind resource additions in line with the proposed Federal Renewable Portfolio Standard (RPS). These additions were modeled as electricity purchase flat contracts for 1,146 MW of wind generation planned from

2003 through 2013 and charged at $50/megawatt-hour (MWh). In the final portfolios, the $50/MWh flat contract was replaced with profiled wind, which is wind whose profile follows an anticipated, more realistic production shape. Under profiled wind, energy deliveries are anticipated to differ in each hour of the day. This profiled wind has been included based solely on its economic merits.

Solar and geothermal opportunities will also be examined on a case-by-case basis for economic merit and inclusion in PacifiCorp's overall resource portfolio.

H2.1.3 Peaking Units

Diversified Portfolio I requires up to 1,200 MW of peaking capacity be added over the action plan period 2006 to 2013 (the equipment market and economics will dictate the actual technology used). Peaking resources are a necessary component of every portfolio, and serve two purposes.

One purpose is to meet the load shape requirements for both the east and west sides of PacifiCorp's system, and the second is to meet the capacity requirements of the 15 percent planning margin. Prior to commitment to build these assets, Purchased Power Agreements (PPAs) and shaped product opportunities will be reviewed and compared for economic benefit, risk reduction, and long-term optionality.

Uncertainty remains regarding the planning margin requirements outlined in FERC's proposed Standard Market Design (SMD). PacifiCorp has designed the action plan based on a 15 percent planning margin. However, it will take a number of years to build to a significant planning margin (even to 10 percent). This period will allow PacifiCorp time to modify its plans in concurrence with the future requirements of SMD. Further study of an appropriate planning margin for PacifiCorp will continue, and is an element of the action plan.

H2.1.4 Base Load Units

In line with the load growth, plant retirement, and contract expiration, an estimated 2,100 MW of base-load capacity is required. Three base-load units in the East (in service in 2008, 2009, and 2012) and one unit in the West (in service in 2007) will be further researched and pursued. The process of sizing and selecting resources consistently identified base load as having desirable least-cost characteristics.

For IRP modeling purposes, and in line with the market depth and liquidity issues discussed in the IRP, it is assumed that these base-load units will be physical assets. However, these units could feasibly be replaced with a long-term PPA. Prior to commitment to build any of these assets, PPAs or other asset purchase opportunities will be reviewed and compared for economic benefit, risk reduction, and long-term optionality.

H2.1.5 Shaped Products and Power Purchase Agreements

Diversified Portfolio I requires approximately 700 MW of shaped products or PPAs throughout the plan period 2004 to 2013. These contracts will fill an immediate short-term peaking need in the East, prior to any assets being built, and will supplement the building of additional assets in the long-term. Shaped products and PPAs also aim to cover off-peak requirements in the West.

The 700 MWs are in addition to any alternative shaped product or PPAs that may be entered into in relation to the peaking and base-load requirements mentioned above.

H2.2 DEMAND-SIDE MANAGEMENT

PacifiCorp has long been an innovator in energy efficiency programs. In the late 1970s, the company's zero interest weatherization program helped residential customers overcome the financing hurdle for efficiency improvements. The Hood River Conservation Project, in which PacifiCorp and other suppliers weatherized homes in an entire community, provided a national model for what concerted utility efforts can achieve. PacifiCorp sponsored Energy Edge to demonstrate the energy savings possible for new commercial buildings. Similarly, the Super Good Cents program promotes energy-efficient residential construction and the development of new building codes for efficiency. The Energy FinAnswer program offers financing and other incentives to commercial and industrial customers for load reduction projects.

PacifiCorp views an appropriately sized DSM program as a means of deferring the need for investments in new plants and as a means to help the company in meeting the challenges of an increasingly competitive environment.

PacifiCorp's DSM programs will continue to be an integral component of the IRP planning process. New and existing programs will be modeled along with supply-side options to determine the optimal resource portfolio. PacifiCorp's existing programs for 2003 are listed in Table H2.2-1.

Table H2.2-1. DSM programs operating during 2003.

DSM Program Name	Description	Availability
Energy FinAnswer (Schedule 125, enhanced with incentives)	Engineering and incentive package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial, and irrigation.	OR, WA, UT
Lighting Retrofit Incentive (Schedule 116)	Incentives for energy-efficient lighting retrofit projects in commercial and industrial facilities greater than 20,000 sq. ft.	OR, WA, UT
Small Retrofit Incentive (Schedule 115)	Incentives for energy-efficient retrofit projects in commercial and industrial facilities less than 20,000 sq. ft.	OR, WA, UT
Energy FinAnswer (schedules vary by state)	Engineering and financing package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial and irrigation.	WY, ID, CA
Appliance Recycling Program	An incentive program designed to remove inefficient refrigerators from the market.	ID*, UT, WA*
Compact Fluorescent Light (CFL) Bulb Program	Two free CFLs are offered to residential customers through direct mail offer. Provides immediate savings benefits and encourages CFL use.	CA*
Enhanced Audit and Weatherization Program	Residential in-home audit with customer choice of low-interest loan or 25 percent rebate to assist in funding of cost-effective recommended measures. Instant savings measures were added to legislatively mandated audit in mid-2000 in order to "enhance" the offer.	OR
Utah Residential and Small Commercial A/C Load Control Program	Turn-key load control network financed, built, operated and owned by a third-party vendor through a pay-for-performance contract.	UT

Table H2.2-1. DSM programs operating during 2003.

DSM Program Name	Description	Availability
Low-Income Weatherization Program	PacifiCorp partners with community action agencies to provide no-cost residential weatherization services to income-qualifying households.	CA, ID, WA
Do-It-Yourself Home Audit	A residential fuel blind do-it-yourself home energy audit. Customers fill out the form and send it in, company generates a report of cost-effective recommendations and mails to customer.	CA, ID, OR, UT, WA, WY
Do-It-Yourself Web-Based Audit	Residential and small commercial web-based energy audit. Fill in the audit information and program provides an energy analysis of your home or business. Fuel blind audit.	Pilot in WA and possibly UT.
Bonneville Power Administration (BPA) Conservation and Renewable Discount Program	Credits received against company's BPA electricity purchases for incremental energy efficiency and renewable investments. Strategy will be created on how best to leverage these dollars to best benefit PacifiCorp and the communities served by PacifiCorp.	OR*, WA*, ID*
Energy Efficiency Education – Bright Ideas Booklet	Published booklet featuring residential energy use and efficiency information that is mailed to customers on request. Available in English and Spanish.	CA, ID, OR, UT, WA, WY
Low-Income Energy Education Services	Provide qualifying customers energy education and do-it-yourself instruction on how to reduce energy costs and offer minimal direct install assistance to qualifying senior citizens.	OR—Portland area only
Efficient Air Conditioning Program	Provide customer incentives for improving the efficiency of air conditioning equipment and maintaining or converting air conditioning equipment to evaporative cooling technologies.	UT
Energy Education to Schools	Provide classroom instruction to grade school and intermediate students on energy education.	WA, Lower Yakima Valley Schools
Low-Income Conservation	Provide energy education and conservation measure installation services to a minimum of 550 households annually over a 3-year period (beginning FY 2001). Estimated savings per home are 1,636 kilowatt-hours (kWh).	UT
Northwest Energy Efficiency Alliance (NEEA)	A series of conservation programs sponsored by utilities in the region designed to support market transformation of energy efficient products and services in OR, WA, ID. Programs include manufacturer rebates on compact fluorescent bulbs to building operator training courses.	WA, ID
Commercial Retro Commissioning	Pilot program designed to work with customers to recommission the operation of their commercial buildings consistent with how the building was designed to operate.	UT

*Programs under evaluation.

PacifiCorp intends to continue to use DSM as a valuable and cost-effective load management tool.

H2.3 ENERGY AND COST IMPLICATIONS OF LICENSE DENIAL

PacifiCorp's current plan for meeting retail customer demand includes the generation associated with the future FERC license of the Klamath Hydroelectric Project. Should this power be unavailable, its replacement would be required to meet current customer demand. The replacement cost of power lost from the Project can be represented generally using PacifiCorp's current 30-year power cost projections (split of Mid-Columbia and COB 30-year cost forecast).

If PacifiCorp were not able to generate power at the Klamath Hydroelectric Project, replacement power would likely be purchased, at least in the short-term, on the open power market. The Project operates during peak and off-peak demand periods. The average cost of on-peak generation, assuming a 30-year average value of COB and Mid-Columbia values ($70 per MWh) and a future on-peak generation of 447,209 MW hours (proposed Project), is $32.9 million per year. The average cost of off-peak generation, assuming a 30-year average value of COB and Mid-Columbia values ($62 per MWh) and a future off-peak generation of 249,834 MW hours (proposed Project), is $15.6 million per year. The total annual replacement cost using above cost values of power is $48.0 million per year.

In general, the energy replacement cost would be proportionately borne by PacifiCorp’s wholesale and retail customers.

Power from the Project serves PacifiCorp residential and commercial customers in southern Oregon and northern California. Larger communities in the area include Klamath Falls, Medford, and Ashland in Oregon, and Yreka in California. Without the local generation, PacifiCorp would need to acquire power from another local source, such as the City of Klamath Falls Cogeneration Plant located in Klamath Falls, Oregon, or it would obtain power from outside the area and wheel it into the southern Oregon area via Bonneville Power Administration (BPA) transmission lines, thereby incurring fees for purchasing and wheeling the power.

The Project has the capacity to generate 151 MW at full load under existing conditions and 147.2 MW under the proposed modified license. The generators connect to PacifiCorp’s transmission system through a number of substations. Currently, the East Side and West Side powerhouses are connected via a substation next to the West Side powerhouse (West Side substation). Keno dam does not generate power. J.C. Boyle has a substation adjacent to the powerhouse. Copco No. 1, Copco No. 2, Fall Creek, and Iron Gate powerhouses are connected via a substation near the Copco No. 2 powerhouse. These substations are essential to the greater transmission system in the area and would need to remain even if the Project was removed. Because it is essential, the West Side substation near the West Side powerhouse will remain in operation, even though the East Side and West Side developments are proposed for decommissioning.

If generation were to cease at the Klamath Project, PacifiCorp would still be able to service its local customers. Non-Project substations would remain available to supply power throughout the Project area. (See Exhibit F, Figures A2.1-2 and A2.1-3.)

The local transmission system has been designed to service customers using power from the Project. If the Project ceased operations or if operations were dramatically altered, transmission improvement projects would be needed to provide reliable load service to Klamath basin customers. Such projects are forecasted as follows: (1) Install two additional capacitors in the Project area; (2) Install a transformer at Copco, and (3) Complete reconductoring of two 230-kilovolt (kV) lines. The estimated conceptual-level cost to complete these projects is about $5,600,000.

When operating, the Project provides voltage support to the local electrical system and reduces the voltage support required from the adjacent substations and the transmission system. When not in operation, power and voltage are provided by other PacifiCorp resources.

The capacity of given hydroelectric plants to pick up load quickly has made them a valuable resource for meeting spinning reserve obligations. Operation reserve requirements use the Western System Coordinating Council (WSCC) and NWPP guidelines. The guidelines identify spinning and nonspinning reserves. The WSCC requires its members to maintain the following operating reserve: sufficient spinning reserve to provide regulating margin, plus an additional amount of operating reserve equal to the sum of 5 percent of committed hydroelectric generation and 7 percent of committed thermal generation (at least half of which must be spinning reserve). PacifiCorp uses the Copco No. 1 and No. 2 powerhouses to meet part of the company's spinning reserve obligation. When these reserves are unavailable, PacifiCorp uses other, more costly resources to meet spinning reserve requirements. If a new license is not issued that allows Copco No. 1 and No. 2 powerhouses to be used as spinning reserve, PacifiCorp would need to find other resources (most likely thermal generations) to help offset this loss of 47-MW spinning reserve.

If PacifiCorp did not receive a new Project license and the license was transferred to another entity, the energy generated at the Project would still require the use of PacifiCorp's transmission system as an outlet source to deliver the power. The only other option available to another entity would be to construct a redundant system to deliver the generated power to its customers. PacifiCorp cannot calculate another entity's cost of constructing transmission facilities.

PacifiCorp does not use the power associated with the Project for its own industrial facility or related operations, with the exception of Project support buildings.

H2.4 REDUCTION IN EXPENSES IF LICENSE TRANSFERRED

The denial of a license to PacifiCorp would result in increased electric rates for customers. Should the Project power be unavailable, its replacement would be required immediately to meet current customer demand. In the short-term, replacement power would have to be purchased. In the long-term, new plant construction would be required to replace lost power.

While purchasing replacement power may be possible, PacifiCorp could have difficulty purchasing sufficient peak power from the existing power grid. It is estimated that purchased power would be required for a minimum of 4 years prior to the construction completion and permitting requirements for a new replacement facility.

In general, the higher cost of replacement energy would be borne proportionally by PacifiCorp's wholesale and retail customers, thus representing reallocation of costs associated with license denial. More specifically, however, the loss of Project energy would have numerous effects on PacifiCorp's ability to serve the local demands in the Project area.

H3.0 ALTERNATIVE POWER SOURCES

H3.1 CAPACITY AND ENERGY REQUIREMENTS

PacifiCorp currently provides electricity and related energy services to 1.5 million customers in 6 western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. About 40 percent of PacifiCorp's retail sales are to industrial customers, about 30 percent are to commercial customers, and about 30 percent are to residential.

In calendar year 2002, PacifiCorp's retail system energy requirements were 5,867 MW-average (MWa). The winter and summer peak loads were 7,585 MW and 8,511 MW, respectively. PacifiCorp currently meets its overall energy requirements with about 57 percent thermal generation, 5 percent company-owned hydroelectric generation, and 38 percent power purchases. About 65 percent of PacifiCorp's capacity comes from company-owned thermal generating plants, 10 percent from hydroelectric plants, and 25 percent from power purchases. PacifiCorp generally uses its coal plants for most of its base-load needs and its hydroelectric resources to respond to hourly, daily, weekly, and seasonal load fluctuations.

PacifiCorp's annual calendar energy requirements in the year 2011 are forecast to range between 7,081 MWa and 12,148 MWa (Table H3.1-1). The winter and summer coincidental peak load forecast for year 2011 ranges from 9,071 and 9,177 MW, respectively, in the low case to 11,170 and 11,308 MW in the high case. The average annual growth rate percent was determined by the formula (Last year/First Year)^(1/number of years between the first and last year).

Table H3.1-1. Total forecasted energy and peak load requirements for the PacifiCorp system.

	Energy		**Winter Peaks**		**Summer Peaks**	
	Avg. Annual Growth Rate %	**Total MWa at 2011**	**Avg. Annual Growth Rate %**	**Total MW at 2011**	**Avg. Annual Growth Rate %**	**Total MW at 2011**
Low	0.7	7,081	0.1	9,071	0.5	9,177
Medium	2.1	7,594	0.8	9,727	1.3	9,875
High	3.3	12,148	2.2	11,170	2,7	11,308

Operation reserve requirements use the WSCC and NWPP guidelines. Operating reserves ensure day-to-day reliability. The guidelines identify spinning and nonspinning reserves. The WSCC requires its members to maintain the following operating reserve: sufficient spinning reserve to provide regulating margin, plus an additional amount of operating reserve equal to the sum of 5 percent of committed hydroelectric generation and 7 percent of committed thermal generation (at least half of which must be spinning reserve).

H3.2 COST OF ALTERNATE SOURCES OF POWER

As a part of the IRP analysis, a variety of alternative supply-side and demand-efficiency resource acquisitions were evaluated. For comparative purposes, capital cost of alternate supply-side resources are presented in Table H3.2-1. The replacement cost is specific to the Project and is based on a future Project total generating capacity of 147.2 MW. The annual cost is based on an average annual Project generation of 693,965 MWh. This value is the total Project long-term

(30-year) average generation, not including generation from the East Side and West Side developments, both of which are proposed for decommissioning. Costs are developed annually by the PacifiCorp Hydro Resources Department.

Table H3.2-1. Capital cost of alternate supply-side resources.

Source	$/kW	Project Replacement Cost ($ millions)[1]	Estimated Annual Cost to Replace Project Power[2] ($ millions)
Natural Gas	697	103	27.7
Cogeneration	917	135	31
Wind	1,067	157	26.7
Coal	1,754	258	21.6

[1] Cost estimates derived from January 2003 IRP Appendix C, Table C.18.

[2] Cost estimate includes the Project replacement cost.

H3.2.1 Natural Gas-fired Resources

The best available technology for utilizing natural gas is a combined-cycle combustion turbine (CCCT). CCCT technology is mature and commercially available. Construction lead times are about 2 years, with another 2 years needed for the necessary permits. Environmental impact is low, with the greatest problem being nitrogen oxide (NO_x) emissions, but control technologies are available.

The advantage of a CCCT is the relatively low capital cost. The main disadvantages of a CCCT are its high heat rate (for example, CCCTs require more fuel to produce a kilowatt-hour [kWh] of electricity compared to a coal plant) and uncertainty over the future cost and supply of natural gas. The estimated capital cost for a CCCT unit in Oregon is $697/kW. To meet the Project production using natural gas-fired resources would cost an estimated $103 million in capital to build a plant. Annual operations, including the cost of capital, would be an estimated $27.7 million per year.

H3.2.2 Cogeneration

Cogeneration facilities require extraction steam from a factory or industrial plant. The technology is mature and commercially available. Siting a cogeneration plant should be relatively straightforward. The difficulty with this technology is partnering with the industrial user. The estimated capital cost for siting a cogeneration facility in Oregon, Washington, or California is $917/kW. To meet the Project production using cogeneration facilities would cost $135 million in capital to build a plant. Annual operations, including the cost of capital, would be an estimated $31 million per year.

H3.2.3 Wind

Wind turbine technology has changed significantly over the past decade and is now entering a third generation of development and testing. Units in the 50- to 500-kW range are a proven technology. Advantages of wind power include size flexibility, minimum environmental impact, no fuel cost, and a short lead time for construction.

Disadvantages of wind power include a low capacity factor, variable energy source (i.e., wind), and potential aesthetic and wildlife impacts. Wind is also a difficult resource to schedule without disrupting other, existing energy resources in that it requires additional reserves from other energy resources to offset its output variations. Thus, wind turbines do not provide predictable capacity (or reserves). Potential wildlife consequences of wind power result from construction, which can disrupt terrestrial species habitat, and from operation, which may particularly affect raptors when they collides with turbine propellers. Noise and public safety are also potential concerns.

Capital cost for wind resource development is estimated at $1,067/kW for the Oregon, Washington, and California region. To meet the Project production using wind facilities would cost an estimated $157 million in capital to build a plant. Annual operations including the cost of capital would be an estimated $26.7 million per year.

H3.2.4 Coal

There are large coal reserves in western North America. While coal-fired generation has higher capital cost and longer lead time for construction, coal fuel operating costs can be much lower than the operating cost of a natural gas generator. This is especially true if the coal plant can be built near the coal reserve, thus avoiding the need to transport the coal great distances. Further, coal costs are historically less volatile than natural gas costs. Because coal reserves are not located close to large metropolitan areas (i.e., where the large blocks of retail load are located), it becomes necessary to carefully assess the capability of the transmission grid to move the electricity from a new coal-fired generating plant to the load it will be serving.

Integrated Gasification Combined Cycle (IGCC) is a clean coal technology that uses a coal gasification process to produce clean fuel gas that can then be used to fuel a combined-cycle gas turbine. This technology can achieve slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant. However, IGCC is only now beginning to reach full commercialization. There are a half a dozen or so commercial plants in the world to date, and most of these are fueled by petroleum residuals. Work is being done to improve their operation on both coal and petroleum residuals, and progress in this area is expected. Capital and operating costs are now higher than those of traditional coal-fired plants, but these could decline as larger economies of scale are reached.

Because PacifiCorp needs future generation to meet forecasted customer demands, the company is currently reviewing Project economics of three possible coal projects in the Utah or Wyoming area. The capital cost of the projects range from $1,582/kW to $2,056/kW. The average of the three estimated capital costs for coal options is $1,754/kW (this number was used to estimate replacement costs and annual operations). To replace the Project production using coal resources would cost an estimated $258 million in capital. Annual operations, including the cost of capital, would be an estimated $21.6 million per year.

H3.3 PURCHASING MARKET POWER

If PacifiCorp did not receive a new Project license, the company, at least in the short-term, would need to obtain replacement power purchased on the open market. The market value of energy is based on incremental power cost estimates as provided by internal market clearing price models. These represent the marginal opportunity cost (or market value) of power, using an average of California-Oregon-Border (COB) and Mid-Columbia values. The market value of energy is calculated using the on-peak and off-peak prices times the long-term (30-year) average on-peak and off-peak megawatt hours (MWh) generated by the proposed Project.

The annual average value of power for the 30-year license period (starting in 2006) is estimated to be $70 per MWh. The range around this estimate is from a low of $56 per MWh to a high of $83 per MWh. Elements that influence the estimate include actual river flows through the Project and the value of power at any given time.

The Project operates during peak and off-peak demand periods. The average value of on-peak generation, assuming a 30-year average value of COB and Mid-Columbia values ($74 per MWh) and a future on-peak generation of 447,209 MWh (proposed Project), is $32.9 million per year. The average value of off-peak generation, assuming a 30-year average value of COB and Mid-Columbia values ($62 per MWh) and a future off-peak generation of 249,834 MW hours (proposed Project), is $15.6 million per year.

H3.4 PLANS TO MODIFY PROJECT FACILITIES AND OPERATION

PacifiCorp plans to make additions in the future to enhance the generation capabilities of existing turbine-generator units at the Project. In general, the driver for overhauling and upgrading a turbine or generator will be the need to replace major components that have reached the end of their useful life. While turbine technology has not changed significantly in many years, the advent of more powerful computers and numerical flow analysis has allowed for optimization of turbine runner designs, resulting in efficiency and capacity gains associated with a turbine overhaul incorporating a runner replacement. In this manner, and considering the length of a new license, PacifiCorp expects to take advantage of the new design and analysis technology to obtain incremental gains to the efficiency and capacity for Project units. Implementation of such upgrades will be determined by the condition of generating equipment and future stream flow conditions through the Project. PacifiCorp is not proposing modifications to its operation that would affect flow releases downstream of Iron Gate dam.

The company is also proposing to decommission the East Side and West Side developments, which will reduce the capacity of the Project from 151 MW to 147.2 MW.

Table H3.4-1 identifies the current schedule for generation maintenance and the decommissioning of the East Side and West Side developments.

Table H3.4-1. Generation maintenance and decommissioning schedule (subject to future revision).

Location	Schedule
East Side and West Side	Developments are proposed for decommissioning in the first year of new license.
J.C. Boyle	Runner Replacement 2005/2006, Generator Overhauls—one in 2005 and another in 2006.
Copco No. 1	Runner Replacement at unit 12 in 2009/2010, Generator Overhauls (one unit in 2022 and the other in 2029).
Copco No. 2	Turbine Replacement 2007, Generator Overhauls (one unit in 2006 and 2030, the other in 2023).
Fall Creek	Turbine Replacements, two different units: one in 2023 and another in 2030. Generator Overhaul—one in 2023 and another in 2031.
Iron Gate	Runner Replacement in 2005/2006 and Generator Overhaul in 2017.

H3.5 CONFORMANCE WITH COMPREHENSIVE PLAN FOR WATERWAY

PacifiCorp is planning to increase the generation capacity of some facilities in the future (see Section H3.4). However, none of the upgrades will result in the need for enlarging the capacity of the current Project waterways. The company also is proposing the decommissioning of the East Side and West Side developments, which will result in a reduction of 3.8 MW in Project capacity. The identified generation capacity projects and the decommissioning of the developments should in no way further affect Klamath River flows coming into or leaving downstream through the Project. USBR, as owner of the Link River dam, will remain responsible to release flows from the dam that are needed to meet downstream ESA obligations at Iron Gate dam.

H4.0 INDIAN TRIBES POTENTIALLY AFFECTED BY THE PROJECT

No portion of the Project is located on Indian reservation land. However, tribal use of the area is well documented. The Project is located on ceded territory of the Klamath Tribes. Shasta tribal members also have cultural ties to portions of Project lands. In addition to the Klamath Tribes, four additional federally recognized tribes are located along the Klamath River downstream of the Project. They include the Karuk Tribe of California, the Hoopa Tribe, and the Yurok Tribe. Resighini Rancheria is also located within the Yurok reservation near the mouth of the Klamath River. The Quartz Valley reservation is located south of the river near Fort Jones, California. Throughout the relicensing process, PacifiCorp consulted with the following Indian tribes:

H4.1 FEDERALLY RECOGNIZED TRIBES

- Klamath Tribes
  PO Box 436
  Chiloquin, OR 97624

- Karuk Tribe of California
  PO Box 282
  Orleans, CA 95556

- Hoopa Tribe
  PO Box 1348
  Hoopa, CA 95546

- Yurok Tribe
  15900 Hwy. 101 N.
  Klamath, CA 95548

- Resighini Rancheria
  PO Box 529
  Klamath, CA 95548

H4.2 NONFEDERAL TRIBAL ORGANIZATIONS

- Shasta Tribes, Inc.
  PO Box 773
  Yreka, CA 96097

- Shasta Nation
  PO Box 5385
  Bend, OR 97708

H5.0 HISTORICAL AND DAILY PROJECT OPERATION

H5.1 PROJECT OPERATION

The following is a brief description of the existing daily Project operations by development using information available in Exhibit B of the final license application. Exhibit B provides individual development overviews, ownership and contractual obligations (if present), operations descriptions, a description of plant control, and any periodic special operations. Some of these Project operations are proposed to be modified in the new license. These include the decommissioning of the East Side and West Side developments, new minimum instream flows in certain Project reaches (see Table E4.2-26 in Exhibit E of this final license application), and new ramp rates and other flow change limitations in certain reaches. (See Exhibit E for a complete description of proposed operational and enhancement measures.)

H5.1.1 West Side

The West Side development is proposed for decommissioning and as such is not a development included in the proposed future Project. This section describes the existing development operations.

Owing to the design and turbine type of the horizontal Francis unit in the West Side powerhouse, the powerhouse can only operate under full flow, which is 230 cfs. Generation from the West Side powerhouse is possible when downstream flow needs at Iron Gate dam exceed the sum of the East Side powerhouse hydraulic capability and the minimum instream flow in the Klamath River below the Link River dam, or when there is spill available from Upper Klamath Lake.

The West Side powerhouse operates in a manual mode that includes manual watering up and dewatering of the conveyance system for planned extended outages or emergencies and all normal unit startup and shutdowns. The West Side generating unit is “block loaded” by setting the control on “head-level” indication, setting inlet canal flows at the dam, and allowing the unit to produce at its full capacity only. The Hydro Control Center provides monitoring only (no control) of the canal flow and unit generation. Local operators are notified of any needed changes to the plant’s operation unless an electrical emergency occurs and HCC is forced to trip the unit off-line.

H5.1.2 East Side

The East Side development is proposed for decommissioning and as such is not a development included in the proposed future Project. This section describes the existing development operations.

The East Side powerhouse operates continuously and does not vary generation according to customer demand. The powerhouse generates with flows provided from Upper Klamath Lake to meet downstream needs, including USBR’s Klamath Irrigation Project and ESA flows downstream of Iron Gate dam. The exception to this type of operation occurs during late July into October, when the powerhouse operates in a diurnal fashion, reducing flows through the facility at night to 200 cfs. This operation minimizes entrainment of federally listed fish (Lost River and shortnose suckers).

The East Side powerhouse is operated both manually and automatically. Manual operation includes manual watering up or dewatering of the water conveyance system before and after planned, extended outages. PacifiCorp personnel are present for normal unit startup and shutdown. For monitoring and control of project flows and generation, PacifiCorp's HCC in Washington is able to provide service 24 hours per day, 7 days a week. HCC adjusts unit loading to meet downstream flow requirements until those adjustments require additional manual changes by the local Project operator. Any time that monitoring and control is not available from HCC, local personnel are able to staff the plant or shut the unit down until any problems are rectified.

H5.1.3 Keno

The Keno development is proposed for removal from the existing FERC Project and as such is not a development included in the proposed future Project. This section describes the existing development operations.

Keno dam is a reregulating facility with no power generating capability. The dam regulates the varying flows in and out of the Klamath River between Link River and Keno dam. As much as possible, Keno dam is operated to maintain a steady reservoir elevation, while continuing to provide enough water to meet flow requirements at Iron Gate dam. The steady reservoir elevation allows USBR to manage its irrigation water through its diversion channels and PacifiCorp to more effectively plan load following operations at the J.C. Boyle powerhouse.

Keno dam is an automated facility. The gate opening, gate closing, control and monitoring can be provided remotely without local personnel having to be present or involved. This operation is handled by the HCC 24 hours per day, 7 days a week. Local crews provide checks of the facilities and manually adjust gate position to coincide with telemetry values on an as-needed basis. During high runoff periods when spill releases exceed the capacity of the controlled gates, the field crew adjusts the locally controlled gates and provides a new operating range for the auto-remote controlled gates.

H5.1.4 J.C. Boyle

The J.C. Boyle powerhouse is typically operated as a power peaking facility, especially when river flows are less than the maximum turbine hydraulic capacity of 2,850 cfs. Due to current turbine efficiencies, preferred flow is 2,500 cfs and is typically the maximum used at the plant. Power generation (and hence flow through the powerhouse) is shaped to coincide with peak customer electricity demand. During the summer months, peak demand typically occurs on weekdays in the late afternoons and early evenings. In general, on a daily basis, water storage occurs in the J.C. Boyle reservoir at night when generation is not occurring. Given the required ramp rate for the J.C. Boyle powerhouse (9 inches per hour), generation must begin well in advance of peak electric load requirements so that the units are at full generation capacity for the peak demand period. The reservoir usually begins to fill sometime after dark, is full by early morning, and begins to be drawn down again during the daylight hours. Specific periods of release may vary widely depending on the anticipated time of peak demand and available river flow.

The operation of the J.C. Boyle development is automated. The operation of the two turbine-generator units is prescribed from a daily generation schedule established by PacifiCorp's

Wholesale Energy Services to meet the power demands of the system while passing required flows through the various river system plants. The HCC has the primary responsibility to blend the timed generation from this plant into the system. It monitors, controls, and initiates all unit startups and shutdowns 24 hours a day, 7 days per week. On unit startup, generation loads are set and the unit automatically reaches and holds that requirement until the Project Hydro Control Operator resets or shuts down the unit. In case of any equipment malfunction or communication interruption, HCC will contact local operators to control the operation manually from the powerhouse.

H5.1.5 Copco No. 1 and No. 2

Copco dam is operated for power generation, some minor flood control, and control of water surface elevations of Copco and Iron Gate reservoirs. Copco No. 1 powerhouse usually operates as a load-factoring (peaking) facility, typically from spring to high flows in early winter. As a load-factoring facility, it is operated to generate during the day when energy demands are highest, and to store water during the nonpeak times (weeknights and weekends). When river flows are near or in excess of turbine hydraulic capacity, the powerhouse generates continuously and excess water is spilled through the spill gates.

Copco No. 1 and No. 2 operate together as load-factoring facilities. Copco No. 2 has virtually no storage reservoir so operates essentially as “a slave” to Copco No. 1. That is, Copco No. 2 generation and hydraulic discharge must operate exactly synchronously with Copco No. 1 generation and hydraulic discharge. Because flows through the system must be closely coordinated owing to lack of significant storage between the projects and mandatory downstream flow requirements, flow through the Copco plants typically mimics flow (with a time lag) through J.C. Boyle on a daily average basis.

Both the Copco No. 1 and No. 2 units are automated and can have the units start, stop, and be controlled from any designated remote site. The units are regulated by a daily generation schedule established by WES to meet the power demands of the system while passing required flows through the various river system plants. The HCC has the primary responsibility to blend the timed generation from this plant into the system. It monitors, controls, and initiates all unit startups and shutdowns 24 hours a day, 7 days per week. Upon unit startups, generation loads are set and the unit will automatically reach and hold that requirement until the local Hydro Control Operator resets or shuts down the unit. In case of any equipment malfunction or communication interruption, HCC will contact Project operators to control the operation manually from the powerhouse.

H5.1.6 Iron Gate

The Iron Gate facility operates as a regulating dam to dampen the effects of fluctuating river levels from the Copco No. 1 and No. 2 load factoring operations. The powerhouse releases flows less than 1,735 cfs, which is the rated hydraulic capacity. When flows are naturally greater or higher, or when flows are needed to meet regulatory conditions downstream, additional water can be passed over the ungated spillway. The amount of spill is controlled to the extent possible through Copco No. 1 and No. 2 operations. If a consistent spill is needed at Iron Gate dam, these powerhouses cannot operate in a load-factoring operation, but must provide a constant flow to maintain Iron Gate reservoir elevations.

The Iron Gate development is primarily operated manually, with minor control provided remotely to serve as the Project's Klamath River regulating facility. Generation schedules provided by WES reflect the instream flow requirements and ramp rates PacifiCorp is obligated to provide. The exception to this may occur seasonally when high runoff river flows cause spills over the uncontrolled spillway at Iron Gate Dam. The single Iron Gate turbine generator unit is scheduled to maintain those regulated flows as well as provide minimal adjustments for seasonal peaks within its range limits. This schedule is given daily to HCC, which is responsible for monitoring and controlling flow releases. Monitoring and control is provided 24 hours a day, 7 days per week. Local operators will start and stop the unit and provide the control to HCC after or before having local control for maintenance functions. HCC, after accepting unit control, can raise or lower generation on a defined (preprogrammed) ramp rate, in which case the control operator must monitor until the new release limit is reached and set. HCC also has the ability to trip the unit if electrical problems occur. Flows to the river will continue through the unit's synchronized bypass valve.

H5.1.7 Fall Creek

The water supply for the Fall Creek powerhouse is predominantly spring fed and is fairly consistent. The facility was designed with no storage reservoir and is operated in a run-of-the-river fashion. The Fall Creek development is operated manually. The manual operation is primarily the result of its run of river operation, smaller generation potential (2.2 MW), and the consistency of the stream flow at the diversion point. The facility is operated at a constant discharge equal to the diversion dam inflow minus the 0.5 cfs instream flow release. The flashboards at the diversion dam are maintained at a constant elevation, and during periods of higher flow, the water in excess of the diversion capacity (50 cfs) passes over the diversion dam. The three units are manually operated as flows become available or diminish seasonally. After normal business hours the units are monitored by HCC through limited critical alarming. The HCC is able to monitor the Fall Creek generation 24 hours per day, 7 days per week from a continuous total generation readout. Should any emergency occur that disturbs unit generation, a critical alarm alerts the HCC, which will contact the local operator to respond on site. Because the units are impulse runners, normal unit shutdowns will deflect flows from the runners and not change flow releases until the operator elects to do so.

Although not part of the existing FERC Project, the Spring Creek diversion dam has been used periodically since 1902 to divert 16.5 cfs of Spring Creek water into Fall Creek for use at the Fall Creek powerhouse. Diverted flow is controlled through a manually operated gate valve at the dam. The Spring Creek facility is proposed for incorporation into the proposed future license.

H5.2 PROJECT MAINTENANCE

The following sections describe maintenance practices at the existing Project. Removal of the East Side, West Side, and Keno developments from the existing Project will only reduce the area of maintenance and not change the practices. It is expected that some practices may change in the future license following completion of cultural, wildlife, and recreation management plans.

H5.2.1 Road Maintenance

Access to nearly all portions of the Project is provided through public or PacifiCorp roads. In general, the company access roads are graded as necessary, and most roads are graveled using commercially obtained rock, or in the case of roads near Copco No. 1, come from a company-owned cinder quarry. To maintain continuous access, necessary roads for Project operations are plowed following significant snows.

H5.2.2 Vegetation Management

Vegetation management occurs along the water conveyance system and on access rights-of-way, as needed. Vegetation management may include hazard tree removal, herbicide application or manual removal of weeds. Vegetation management along access roads is limited and normally involves manual removal of larger tree branches that encroach into the roadway and some brush removal. Minor activity occurs along canals, penstocks, and forebays to control vegetation. As needed, woody plants are either lopped or, preferably, removed by the root along the lined canals, as root growth can cause cracking of the gunnite. Some herbicides (predominately Roundup™) are used at Project facilities (powerhouses and substation) to control vegetation. The herbicides are approved for this type of use and applied by trained personnel. To protect aquatic resources, herbicides are not applied next to Project waterways. Timber management on PacifiCorp property within the FERC boundary includes periodic thinning and silvicultural practices for stand improvement, reduction of hazard, and safety.

H5.2.3 Diversion Maintenance

At each point of diversion, there is a trash rack in front of the waterway head gate. These racks collect large debris and must be raked periodically to maintain maximum flow. Raking frequency is dependent on season. Racks may be raked several times each day during the fall, or during winter and spring freshets. This need is predominantly due to leaf or other wetland plant litter. Another seasonal trash rack concern is icing during exceptionally cold periods. When ice begins forming, crews are dispatched to rake ice from the racks to allow water to keep moving. During the rest of the year, trash racks are inspected daily and raked as needed. Debris cleared from the trash racks is kept on-site and allowed to compost (or melt in the case of ice).

In addition to the trash racks at the J.C. Boyle diversion, the intake has fish screens. The screening facility consists of four rotating screens that require maintenance in the form of debris removal (as needed) and periodic hole patching or screen replacement.

H5.2.4 Forebay Maintenance

The East Side project is the only facility with a traditional forebay. All of the other powerhouses are fed via a canal-penstock system or directly from a reservoir. The East Side forebay, being immediately downstream of Upper Klamath Lake, has little need for sediment removal activities. The lake passes only minor accumulations of suspended sediment. The rock wall that forms half of the forebay is inspected periodically. Dewatering of the forebay is not needed to complete the inspection.

H5.2.5 Canal Maintenance

The canal sections of Project waterways are surveyed annually for maintenance needs. Inspected canals include the West Side canal, J.C. Boyle canal, and the Fall Creek canal. In the case of the J.C. Boyle canal, the canal is dewatered annually to clear the canal and allow inspection. In general, canal work generally consists of removing large rocks and gravel deposits, and patching cracks in the gunnite or other minor structural repairs. The work is generally done in the months of May and June and typically lasts 1 to 2 days, depending on the amount of material to be removed. Material removed from the canals is typically deposited at the most accessible location, such as the side of the roadway adjacent to the Fall Creek canal. Overall, the amount of material deposited is an inconsequential quantity of rock and gravel.

H5.2.6 Flowline, Tunnels, and Penstock Maintenance

Each of the seven powerhouses has steel penstocks associated with their respective water conveyance system. The East Side development has a flowline consisting of half woodstave and half steel. The J.C. Boyle waterway has a short steel flowline near the dam and a tunnel section feeding the penstocks. Copco No. 2 has woodstave and rock tunnel sections. Most maintenance of these conveyance types is focused on the woodstave sections owing to their deteriorated condition (both the East Side and Copco No. 2 woodstave flowlines are 79 years old). Activities include repairing leaks (to extent possible) and vegetation control. In extreme cases, maintenance has included lining the inside of the flowline. Tunnel inspections and debris removal typically occur every 5 years. Depending on type of maintenance outage, they may occur more often. Penstock footings are periodically surveyed to assess movement, erosion, or settling.

H5.2.7 Powerhouse Maintenance (e.g., Turbines, Generators)

PacifiCorp makes every effort to maximize the use of water resources in the operation of all of its hydroelectric facilities. With the availability of two generating units at J.C. Boyle, Copco No. 1 and No. 2 powerhouses, it is possible to remove one unit from service during periods when inflows are insufficient for two unit operations. This step allows maintenance to be performed without causing a loss of generation. Even during times when there is available water for operation of both units at Copco No. 1 and No. 2, it is often possible to shut the units down for a short period to make minor repairs, store the majority of water in the reservoir, and still provide a minimum flow downstream of Iron Gate dam. Unless both units are out of service at the same time, typically no loss of generation occurs.

H5.3 PROJECT OPERATION DURING FLOOD CONDITIONS

During high-water conditions, plant personnel may open the spillway gates and maintain full generation. Spill occurs at Link River dam when the outflow of Upper Klamath Lake is greater than the combined East Side and West Side powerhouse capacity of 1,430 cfs. Link River dam has a spillway capacity of 13,000 cfs. Spill at Keno dam is continuous, and the total spill capacity of the dam is 35,000 cfs at elevation of 4,082 ft msl. Spill occurs at J.C. Boyle dam when incoming river flows are greater than 2,850 cfs. The spillway discharge capacity for the J.C. Boyle dam is 29,100 cfs at elevation 3,797.8 ft msl. Downstream at Copco No. 1 and No. 2, spill occurs when flow is greater than 3,200 cfs, the hydraulic capacity of each powerhouse.

Spillway discharge capacity at Copco No. 1 dam is 44,800 cfs at 2,611.3 ft msl and 25,000 cfs at Copco No. 2. Flows greater than 1,750 cfs at Iron Gate dam will spill over the spillway dependent on reservoir elevation. At Iron Gate, the ungated spillway capacity is 74,400 cfs at 2,345.4 msl. In the case of very high flows and under emergency circumstances, a low-level tunnel may be opened to pass an additional 3,800 cfs. Flow through the tunnel is managed via a slide gate, which can only be operated at the project. The flow capacity of the Fall Creek powerhouse is 50 cfs so any additional flow goes over the spillway. During periods of high flow, Project facilities may be checked several times per 24-hour period, or staffed continually if needed.

During high runoff season, PacifiCorp will frequently target to draft Copco and Iron Gate reservoirs by 4 to 7 vertical feet each. The vacant storage created by this draft is then available to manage all or some portion of high flows as they develop from subbasin tributaries downstream of Link River dam and upstream of Iron Gate. This vacant storage also assists flows below Iron Gate dam to be better managed until the effects of any flow reductions from Upper Klamath Lake and Keno reach the downstream reservoirs.

H5.4 PROJECT SAFETY

The Project has both reservoir and river flow alarms to notify PacifiCorp's HCC of nontypical elevations or flows. Keno, Copco, and Iron Gate reservoirs all have water surface alarms. River gauge alarms are in place at the Link River gauge between the East Side and West Side powerhouses and at the Iron Gate gauge downstream of the powerhouse.

To provide public awareness, warning signs are posted along the river, downstream of the hydro-facilities, which warn the public that rapid water level fluctuations may occur.

PacifiCorp personnel conduct a visual inspection of Project facilities on a regular basis to detect signs of structural movement, seepage, equipment failure, or water conduit failure. Horizontal and vertical displacement markers have been installed on the dams and adjoining foundations. The markers are surveyed annually and compared to previous benchmark readings.

PacifiCorp has installed additional sensors and alarm equipment throughout the powerhouses and included them in the Program Logic Control (PLC) system, which sends information to the Dispatcher via PacifiCorp's microwave system. Alarms and telemetry data are monitored 24 hours per day, 7 days per week.

The PLC alarms include generator status (unit status, generator circuit breaker status, wicket gate lock status), generator critical alarms (e.g., generator lockout, kingsbury low oil, guide-bearing low oil/low pressure, governor low oil/low pressure, kingsbury cooling water low flow, unit brakes low air, bearing temperature), substation equipment alarms (breaker status), substation critical alarms (auxiliary equipment), substation noncritical alarms (low pressure/temperature alarms), generator bus lockout, step-up transformer lockouts, station battery trouble, station heat/smoke alarms, and entry alarms.

The PLC telemetry system provides information on unit generation, transformer loading, and bus voltage. One of the functions of the system is to transmit reservoir water level, tailrace water level, and rate of change data to the dispatcher. In addition to alarm and telemetry functions, the system has control features that enable the dispatcher to control generating units. The PLC system and associated sensors and detectors are tested by PacifiCorp's technical personnel on a regular basis.

The Project is inspected annually by FERC and the state of California's Department of Water Resources Division of Safety of Dams. It is also inspected by an independent engineering consultant every 5 years in accordance with Part 12 of the FERC regulations (18 CFR), and a report of the findings is filed with the FERC regional director.

H5.5 PACIFICORP'S SAFETY RECORD

In 1988, FERC required that PacifiCorp develop an Emergency Action Plan (EAP) for the Project that is consistent with the Federal Guidelines for Dam Safety: Emergency Action Planning for Dam Owners. The purpose of the EAP is to provide early warning to people who may be affected by the sudden release of water caused by natural disaster, accident, or failure of the Project works. The EAP also seeks to minimize the impact on property caused by such an event. The EAP is reissued every 5 years and updated every year. The current EAP for the Project was issued in December 1999 and revised each subsequent year. No Project changes are proposed at this time that would require a new EAP.

In 1992 PacifiCorp submitted the Klamath River Project Public Safety Plan to FERC in accordance with CFR Section 12.42. The Public Safety Plan is a document related to the installation of warning and safety devices. FERC approved the plan for the Project that same year, and the Plan is maintained and updated as needed.

Public access to the nonrecreation facilities of the Project is limited. The dam and powerhouse facilities are locked and fenced. The maintenance and office complex next to the J.C. Boyle dam is fenced with a locked gate. Likewise, the maintenance and office complex next to the Copco No. 2 powerhouse is fenced with a locked gate.

There have been no Project-related fatalities and no known public-related injuries. However, within the general area of the Project, four public fatalities and one injury have occurred since 1998. Three of the fatalities were drownings near the J.C. Boyle development, and one was a heart attack that occurred along the Klamath River in the Klamath canyon. The single injury came to a man who had fallen on rocks while attempting to dive from cliffs into J.C. Boyle reservoir.

PacifiCorp maintains personnel safety records for company employees as required by state and federal laws. For the past 5-year period, there have been two lost-time accidents. One accident (strained back) occurred in 2002 and the second (hernia repair) occurred in 2003.

The Project facilities are inspected on a regular basis by Project personnel. The dams and powerhouses are inspected on a daily basis. As previously noted, the Project is inspected annually by the FERC staff. The EAP drill is also performed annually.

H6.0 PROJECT OUTAGES AND LOST GENERATION

PacifiCorp procedures for reporting forced outages at the Project were updated in 2001. All outages are currently reported digitally and provide the date, time, and duration of the outage, amount of lost generation, and the reason for the outage, including the action taken to correct the cause (Table H6.0-1).

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
Klamath Planned Outages 1/1/2001 through 12/9/2003							
82	01/08/2001 3:29:54 PM	01/12/2001 3:30:00 PM	Copco 22	13	96.00	1,248.00	PO3 - Maintenance Outage
83	01/10/2001 11:10:00 AM	01/10/2001 4:00:00 PM	Copco 11	13	4.83	62.80	PO3 - Maintenance Outage
84	01/16/2001 9:10:00 AM	01/16/2001 3:03:00 PM	Copco 22	13	5.88	76.50	PO3 - Maintenance Outage
85	01/10/2001 9:20:00 AM	01/10/2001 1:55:00 PM	Fall Creek 1	1	4.58	2.30	PO3 - Maintenance Outage
86	01/11/2001 9:20:59 AM	01/11/2001 1:55:00 PM	Fall Creek 3	1	4.57	5.90	PO3 - Maintenance Outage
144	02/13/2001 9:21:00 AM	02/13/2001 5:55:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	8.57	753.90	PO3 - Maintenance Outage
146	02/01/2001 12:00:00 PM	02/01/2001 11:30:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	11.50	1,012.00	PO3 - Maintenance Outage
147	01/12/2001 5:59:00 AM	01/12/2001 5:04:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	11.08	975.30	PO3 - Maintenance Outage
164	03/01/2001 5:00:00 AM	03/01/2001 7:30:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	14.50	1,276.00	PO3 - Maintenance Outage
165	02/26/2001 5:00:00 AM	03/06/2001 2:00:00 PM	East Side	3	201.00	643.20	PO3 - Maintenance Outage
181	03/07/2001 12:00:00 PM	03/07/2001 2:00:00 PM	Copco 11 Copco 21	26	2.00	52.00	PO3 - Maintenance Outage
253	04/16/2001 8:00:00 AM	04/26/2001 12:25:00 PM	J.C. Boyle 2	40	244.42	9,776.70	PO1 - Annual Outage
323	05/14/2001 7:30:00 AM	05/17/2001 5:30:00 PM	Iron Gate	18	82.00	1,476.00	PO1 - Annual Outage
324	04/16/2001 9:56:00 AM	04/16/2001 6:59:00 PM	J.C. Boyle 1	48	9.05	434.40	PO3 - Maintenance Outage
325	05/01/2001 7:15:00 AM	05/03/2001 1:55:00 PM	J.C. Boyle 1	48	54.67	2,624.00	PO1 - Annual Outage
647	10/15/2001 8:00:00 AM	11/09/2001 10:00:00 AM	Copco 22	13	602.00	7,826.00	PO1 - Annual Outage
672	10/29/2001 1:00:00 PM	11/28/2001 1:45:00 PM	Copco 11	13	720.75	9,369.80	PO1 - Annual Outage
924	05/04/2002 4:20:00 PM	05/17/2002 2:30:00 PM	Iron Gate	18	310.17	5,583.00	PO1 - Annual Outage
936	05/21/2002 8:00:00 AM	05/21/2002 6:00:00 PM	Copco 21	13	10.00	130.00	PO2 - Overhaul/Upgrade Outage
937	05/22/2002 8:00:00 AM	05/22/2002 6:00:00 PM	Copco 22	13	10.00	130.00	PO2 - Overhaul/Upgrade Outage
1053	06/07/2002 9:00:00 AM	07/15/2002 4:00:00 PM	Copco 22	13	919.00	11,947.00	PO1 - Annual Outage
1072	05/09/2002 6:00:00 AM	05/16/2002 2:35:00 PM	East Side	3	176.58	565.10	PO3 - Maintenance Outage

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1073	07/22/2002 7:00:00 AM	08/02/2002 12:00:00 PM	J.C. Boyle 1	48	269.00	12,912.00	PO1 - Annual Outage
1090	08/05/2002 9:30:00 AM	08/09/2002 2:10:00 PM	J.C. Boyle 2	40	100.67	4,026.70	PO1 - Annual Outage
1091	08/19/2002 8:40:57 AM	08/27/2002 12:10:00 PM	Copco 21	13	195.48	2,541.30	PO1 - Annual Outage
1107	07/15/2002 4:00:00 PM	07/17/2002 2:00:00 PM	Copco 11	13	46.00	598.00	PO3 - Maintenance Outage
1108	06/06/2002 8:00:00 AM	07/15/2002 9:00:00 AM	Copco 12	10	937.00	9,370.00	PO2 - Overhaul/Upgrade Outage
1238	09/15/2002 2:00:00 PM	10/11/2002 1:30:00 PM	J.C. Boyle 1	45	623.50	28,057.50	PO2 - Overhaul/Upgrade Outage
1239	09/15/2002 2:00:00 PM	10/11/2002 1:30:00 PM	J.C. Boyle 2	42	623.50	26,187.00	PO2 - Overhaul/Upgrade Outage
1273	12/02/2002 7:00:00 AM	12/03/2002 8:00:00 PM	J.C. Boyle 2	42	37.00	1,554.00	PO4 - Non-Generation Issue
1274	12/02/2002 7:00:00 AM	12/03/2002 8:00:00 PM	J.C. Boyle 1	45	37.00	1,665.00	PO3 - Maintenance Outage
1315	01/24/2003 1:25:08 PM	01/24/2003 2:02:00 PM	Iron Gate	19	0.62	11.60	PO3 - Maintenance Outage
1414	10/25/2002 8:00:00 AM	12/19/2002 12:00:00 PM	West Side	1	1,324.00	794.40	PO1 - Annual Outage
1441	02/07/2003 9:00:00 AM	02/07/2003 4:00:00 PM	J.C. Boyle 1 J.C. Boyle 2	87	7.00	609.00	PO3 - Maintenance Outage
1442	02/25/2003 8:00:00 AM	02/25/2003 2:00:00 PM	East Side	3	6.00	19.20	PO3 - Maintenance Outage
1443	03/24/2003 12:00:00 PM	03/24/2003 4:30:00 PM	J.C. Boyle 1 J.C. Boyle 2	87	4.50	391.50	PO3 - Maintenance Outage
1444	03/25/2003 11:00:00 AM	03/25/2003 12:30:00 PM	J.C. Boyle 1 J.C. Boyle 2	87	1.50	130.50	PO3 - Maintenance Outage
1495	05/06/2003 10:35:12 AM	05/06/2003 10:51:00 AM	Copco 12	13	0.27	3.40	PO3 - Maintenance Outage
1511	05/12/2003 6:10:51 AM	05/14/2003 4:21:36 PM	Iron Gate	19	0.00	0.00	PO1 - Annual Outage
1557	6/15/2003 9:47:28 AM	6/22/2003 3:00:20 PM	J.C. Boyle 1 J.C. Boyle 2	87	173.22	15,069.90	PO2 - Overhaul/Upgrade Outage
1723	8/11/2003 7:15:00 AM	8/15/2003 12:42:00 PM	East Side	3	101.45	324.60	PO1 - Annual Outage
1749	9/15/2003 7:00:38 AM	9/19/2003 2:37:31 PM	Copco 22	15	103.62	1,502.40	PO1 - Annual Outage
1761	9/19/2003 9:30:19 AM	9/19/2003 12:00:19 PM	Fall Creek 1	1	2.50	1.50	PO3 - Maintenance Outage
1763	9/22/2003 7:00:55 AM	9/25/2003 4:45:33 PM	Copco 12	13	81.75	1,038.20	PO1 - Annual Outage
1773	9/24/2003 8:00:45 AM	9/24/2003 2:00:45 PM	J.C. Boyle 2 J.C. Boyle 1	87	6.00	522.00	PO3 - Maintenance Outage

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1774	9/24/2003 8:00:03 AM	9/24/2003 4:30:03 PM	East Side	3	8.50	27.20	PO3 - Maintenance Outage
1777	9/29/2003 7:00:21 AM	10/3/2003 12:45:21 PM	Copco 11	14	101.75	1,424.50	PO1 - Annual Outage
1802	10/23/2003 8:50:50 AM	10/23/2003 10:22:50 AM	East Side	3	1.53	4.90	PO3 - Maintenance Outage
1805	10/27/2003 2:30:23 PM	10/27/2003 5:00:23 PM	Copco 22	15	2.50	36.30	PO3 - Maintenance Outage
1806	10/27/2003 10:00:36 AM	10/27/2003 2:30:36 PM	Copco 21	15	4.50	65.30	PO3 - Maintenance Outage
1807	10/28/2003 9:00:40 AM	10/28/2003 2:00:40 PM	Copco 12	13	5.00	63.50	PO3 - Maintenance Outage
1808	10/28/2003 2:00:26 PM	10/28/2003 4:30:26 PM	Copco 11	14	2.50	35.00	PO3 - Maintenance Outage
1809	10/30/2003 7:00:42 AM	10/30/2003 8:30:42 AM	Copco 11	14	1.50	21.00	PO3 - Maintenance Outage
1810	10/30/2003 8:30:12 AM	10/30/2003 9:00:12 AM	Copco 12	13	0.50	6.40	PO3 - Maintenance Outage
1811	10/30/2003 9:10:25 AM	10/30/2003 12:00:25 PM	Copco 22	15	2.83	41.10	PO3 - Maintenance Outage
1873	11/29/2003 1:20:54 PM	11/29/2003 4:06:54 PM	J.C. Boyle 2 J.C. Boyle 1	42	2.77	116.20	PO3 - Maintenance Outage
1875	12/2/2003 9:00:28 AM	12/2/2003 12:00:28 PM	J.C. Boyle 1 J.C. Boyle 2	87	3.00	261.00	PO3 - Maintenance Outage
1877	12/3/2003 8:00:49 AM	12/3/2003 12:00:49 PM	J.C. Boyle 1 J.C. Boyle 2	87	4.00	348.00	PO3 - Maintenance Outage
1895	12/9/2003 9:50:48 AM	12/9/2003 5:00:48 PM	Fall Creek 1	1	7.17	4.30	PO3 - Maintenance Outage
1896	12/9/2003 9:15:21 AM	12/9/2003 5:00:21 PM	Fall Creek 2	1	7.75	3.90	PO3 - Maintenance Outage
1897	12/9/2003 10:30:00 AM	12/9/2003 5:00:00 PM	Fall Creek 3	1	6.50	7.80	PO3 - Maintenance Outage
Klamath Un-Planned Outages 1/1/2001 through 12/23/2003							
81	01/04/2001 5:30:42 AM	01/04/2001 7:44:00 AM	J.C. Boyle 2	40	2.22	88.70	36XX - Electrical Systems
109	01/26/2001 4:50:11 AM	01/26/2001 5:09:00 AM	Copco 11	13	0.32	4.10	39XX - Controls/Communication
145	01/15/2001 8:00:00 AM	02/15/2001 5:00:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	753.00	1,731.90	45XX - Generator/Exciter
177	03/07/2001 2:00:00 AM	03/07/2001 3:02:00 AM	J.C. Boyle 1	48	1.03	49.60	71XX - Water Delivery System
182	03/06/2001 3:00:00 AM	03/06/2001 4:19:00 AM	J.C. Boyle 1	48	1.32	63.20	71XX - Water Delivery System
183	03/07/2001 2:00:00 AM	03/07/2001 3:02:00 AM	J.C. Boyle 1	48	1.03	49.60	71XX - Water Delivery System

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
188	03/01/2001 7:30:00 PM	03/02/2001 12:43:00 AM	J.C. Boyle 1 J.C. Boyle 2	88	5.22	459.10	39XX - Controls/Communication
190	03/04/2001 4:00:00 AM	03/04/2001 4:43:00 AM	J.C. Boyle 1	48	0.72	34.40	71XX - Water Delivery System
201	03/14/2001 8:46:00 AM	03/14/2001 8:56:00 AM	Iron Gate	18	0.17	3.00	99XX - Personnel Error
218	03/22/2001 9:11:37 PM	03/22/2001 10:45:00 PM	Fall Creek 1 Fall Creek 3	2	1.55	2.80	93XX - External Problems
226	03/31/2001 4:19:00 PM	03/31/2001 4:45:00 PM	Copco 21	13	0.43	5.60	99XX - Personnel Error
234	04/04/2001 6:16:00 AM	04/04/2001 12:17:00 PM	Copco 21	13	6.02	78.20	71XX - Water Delivery System
239	04/06/2001 9:55:57 AM	04/06/2001 10:35:00 AM	Iron Gate	18	0.65	11.70	45XX - Generator/Exciter
252	04/17/2001 6:15:00 AM	04/17/2001 6:45:00 AM	Copco 21	13	0.50	6.50	36XX - Electrical Systems
254	04/18/2001 6:17:00 AM	04/18/2001 10:27:00 AM	Copco 21	13	4.17	54.20	36XX - Electrical Systems
262	04/23/2001 6:35:28 PM	04/23/2001 10:50:00 PM	Copco 12	10	4.25	42.50	45XX - Generator/Exciter
272	04/29/2001 6:14:00 AM	04/29/2001 7:34:00 AM	Copco 21	13	1.33	17.30	39XX - Controls/Communication
279	05/02/2001 6:17:51 AM	05/02/2001 6:30:00 AM	Copco 12	10	0.20	2.00	39XX - Controls/Communication
286	05/03/2001 9:10:00 AM	05/03/2001 9:30:00 AM	Fall Creek 3	1	0.33	0.40	99XX - Personnel Error
298	05/10/2001 1:54:00 PM	05/10/2001 2:05:00 PM	Copco 21	13	0.18	2.40	99XX - Personnel Error
301	05/15/2001 12:12:11 AM	05/15/2001 12:28:00 AM	West Side	1	0.27	0.20	39XX - Controls/Communication
302	05/15/2001 12:41:55 AM	05/15/2001 10:23:00 AM	West Side	1	9.68	7.70	39XX - Controls/Communication
433	07/08/2001 1:07:00 PM	07/08/2001 1:25:00 PM	Copco 21	13	0.30	3.90	36XX - Electrical Systems
472	07/18/2001 1:41:00 AM	07/18/2001 2:13:00 AM	East Side	3	0.53	1.70	93XX - External Problems
473	07/18/2001 2:27:00 AM	07/18/2001 6:47:00 AM	East Side	3	4.33	13.90	93XX - External Problems
504	08/04/2001 1:15:00 PM	08/04/2001 2:06:00 PM	Copco 21	13	0.85	11.10	39XX - Controls/Communication
579	09/04/2001 12:26:00 PM	09/04/2001 12:57:00 PM	Copco 21	13	0.52	6.70	39XX - Controls/Communication
611	09/14/2001 9:29:00 AM	09/14/2001 11:10:00 AM	Iron Gate	18	1.68	30.30	93XX - External Problems
612	09/16/2001 11:34:00 AM	09/16/2001 12:00:00 PM	Copco 21	13	0.43	5.60	39XX - Controls/Communication
623	09/28/2001 12:05:00 PM	09/28/2001 12:40:00 PM	Copco 11	13	0.58	7.60	45XX - Generator/Exciter
641	10/12/2001 1:30:00 PM	10/12/2001 4:22:00 PM	Copco 11	13	2.87	37.30	93XX - External Problems

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
748	12/15/2001 5:38:00 PM	12/16/2001 10:12:00 AM	Copco 21	13	16.57	215.40	39XX - Controls/Communication
779	01/06/2002 3:00:00 AM	01/06/2002 4:30:00 AM	J.C. Boyle 1	48	1.50	72.00	39XX - Controls/Communication
780	01/05/2002 3:00:00 AM	01/05/2002 4:37:00 AM	J.C. Boyle 1	48	1.62	77.60	39XX - Controls/Communication
781	01/07/2002 3:00:00 AM	01/07/2002 4:24:00 AM	J.C. Boyle 1	48	1.40	67.20	39XX - Controls/Communication
783	01/07/2002 3:23:00 PM	01/07/2002 5:19:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	1.93	170.10	39XX - Controls/Communication
784	01/08/2002 6:58:00 AM	01/08/2002 7:49:00 AM	J.C. Boyle 1 J.C. Boyle 2	88	0.85	74.80	39XX - Controls/Communication
802	01/28/2002 5:48:00 AM	01/28/2002 2:50:00 PM	Fall Creek 1 Fall Creek 3	2	9.03	16.30	39XX - Controls/Communication
803	01/29/2002 4:20:00 AM	01/29/2002 6:10:00 AM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	1.83	4.20	39XX - Controls/Communication
817	02/11/2002 10:55:54 AM	02/11/2002 10:56:00 AM	Copco 12 Copco 22	23	0.00	0.00	39XX - Controls/Communication
838	03/28/2002 5:30:00 PM	03/28/2002 10:18:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	4.80	422.40	39XX - Controls/Communication
858	03/29/2002 11:45:00 PM	03/30/2002 2:20:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	14.58	1,283.30	39XX - Controls/Communication
859	03/30/2002 4:38:00 PM	04/01/2002 4:31:00 PM	J.C. Boyle 1 J.C. Boyle 2	88	47.88	4,213.70	39XX - Controls/Communication
985	06/13/2002 12:48:00 PM	06/13/2002 1:33:00 PM	Copco 11	13	0.75	9.80	39XX - Controls/Communication
993	06/21/2002 1:21:00 PM	06/21/2002 2:43:00 PM	East Side West Side	4	1.37	5.50	93XX - External Problems
1042	04/16/2002 5:34:00 PM	04/16/2002 9:39:00 PM	Copco 12	10	4.08	40.80	39XX - Controls/Communication
1043	04/17/2002 7:00:00 PM	04/17/2002 7:54:00 PM	Copco 12	10	0.90	9.00	39XX - Controls/Communication
1044	04/17/2002 7:55:00 PM	04/17/2002 8:19:00 PM	Copco 22	13	0.40	5.20	39XX - Controls/Communication
1152	09/26/2002 3:00:00 PM	09/26/2002 3:23:00 PM	Copco 21	15	0.38	5.60	70XX - Turbine
1155	10/01/2002 12:10:00 PM	10/01/2002 12:11:00 PM	Copco 21	15	0.02	0.20	39XX - Controls/Communication

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1160	10/03/2002 11:35:00 AM	10/03/2002 11:44:00 AM	Copco 11	14	0.15	2.10	39XX - Controls/Communication
1161	10/03/2002 11:24:00 AM	10/03/2002 11:51:00 AM	Copco 12	13	0.45	5.70	99XX - Personnel Error
1165	10/04/2002 12:47:23 PM	10/04/2002 12:55:00 PM	Copco 21	15	0.13	1.90	38XX - Auxiliary Systems
1166	10/05/2002 1:48:13 PM	10/05/2002 2:00:00 PM	Copco 21	15	0.20	2.90	38XX - Auxiliary Systems
1168	10/05/2002 8:17:00 AM	10/05/2002 11:19:00 AM	East Side	3	3.03	9.70	93XX - External Problems
1171	10/07/2002 12:53:14 PM	10/07/2002 1:15:00 PM	Copco 21	15	0.37	5.30	38XX - Auxiliary Systems
1174	10/08/2002 9:21:00 AM	10/08/2002 9:34:00 AM	Copco 21	15	0.22	3.10	36XX - Electrical Systems
1186	08/05/2002 12:00:00 PM	08/05/2002 12:07:00 PM	Copco 22	15	0.12	1.70	36XX - Electrical Systems
1193	08/18/2002 12:58:00 PM	08/18/2002 1:24:00 PM	Copco 11	14	0.43	6.10	45XX - Generator/Exciter
1198	10/13/2002 5:00:00 AM	10/13/2002 6:05:00 AM	Copco 11	14	1.08	15.20	70XX - Turbine
1201	08/31/2002 2:12:00 PM	08/31/2002 2:27:00 PM	Copco 22	15	0.25	3.60	39XX - Controls/Communication
1202	09/01/2002 1:58:00 PM	09/01/2002 2:12:00 PM	Copco 22	15	0.23	3.40	39XX - Controls/Communication
1203	09/04/2002 1:16:00 PM	09/04/2002 1:26:00 PM	Copco 11	14	0.17	2.30	70XX - Turbine
1223	10/24/2002 5:30:35 AM	10/24/2002 6:00:00 AM	Copco 11	14	0.48	6.80	38XX - Auxiliary Systems
1224	10/24/2002 5:44:15 AM	10/24/2002 6:00:00 AM	Copco 21	15	0.27	3.90	38XX - Auxiliary Systems
1225	10/25/2002 4:42:17 AM	10/25/2002 4:45:00 AM	Copco 11	14	0.05	0.70	38XX - Auxiliary Systems
1226	10/26/2002 5:26:08 AM	10/26/2002 5:45:00 AM	Copco 11	14	0.32	4.40	38XX - Auxiliary Systems
1227	10/27/2002 12:05:00 AM	10/27/2002 12:56:00 AM	J.C. Boyle 1	45	0.85	38.30	70XX - Turbine
1228	10/28/2002 5:20:00 AM	10/28/2002 6:05:00 AM	Copco 11	14	0.75	10.50	71XX - Water Delivery System
1229	10/28/2002 5:51:00 AM	10/28/2002 6:12:00 AM	Copco 22	15	0.35	5.10	71XX - Water Delivery System
1233	10/29/2002 8:01:00 AM	10/29/2002 8:15:00 AM	Copco 11	14	0.23	3.30	39XX - Controls/Communication
1241	10/30/2002 8:02:00 AM	10/30/2002 8:41:00 AM	Copco 11	14	0.65	9.10	39XX - Controls/Communication
1266	12/07/2002 7:00:00 AM	12/07/2002 8:11:00 AM	Copco 11	14	1.18	16.60	39XX - Controls/Communication
1272	12/12/2002 10:26:05 AM	12/13/2002 11:35:00 AM	Copco 12	13	25.15	319.40	45XX - Generator/Exciter
1278	12/16/2002 7:00:00 AM	12/16/2002 7:41:00 AM	Copco 21	15	0.68	9.90	39XX - Controls/Communication
1280	12/19/2002 7:04:02 AM	12/19/2002 7:26:00 AM	Copco 21	15	0.37	5.30	39XX - Controls/Communication
1293	01/07/2003 8:01:00 AM	01/07/2003 8:13:00 AM	Copco 21	15	0.20	2.90	36XX - Electrical Systems

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1308	01/15/2003 1:12:00 AM	01/15/2003 2:31:00 AM	Copco 22	15	1.32	19.10	39XX - Controls/Communication
1309	01/18/2003 8:09:00 AM	01/18/2003 8:30:00 AM	Copco 21	15	0.35	5.10	39XX - Controls/Communication
1316	01/28/2003 12:44:00 PM	01/28/2003 12:59:00 PM	Iron Gate	19	0.25	4.70	39XX - Controls/Communication
1326	02/07/2003 7:42:00 AM	02/07/2003 8:09:00 AM	Copco 11	14	0.45	6.30	71XX - Water Delivery System
1327	02/07/2003 8:02:00 AM	02/07/2003 8:28:00 AM	Copco 21	15	0.43	6.30	71XX - Water Delivery System
1332	02/13/2003 8:00:00 AM	02/13/2003 8:12:00 AM	Copco 21	15	0.20	2.90	39XX - Controls/Communication
1333	02/13/2003 8:00:00 AM	02/13/2003 8:16:00 AM	Copco 22	15	0.27	3.90	39XX - Controls/Communication
1341	02/16/2003 10:00:00 AM	02/16/2003 10:07:00 AM	Copco 11	14	0.12	1.60	70XX - Turbine
1342	02/15/2003 8:05:00 AM	02/15/2003 8:10:00 AM	Copco 21	15	0.08	1.20	39XX - Controls/Communication
1345	02/18/2003 7:56:00 AM	02/18/2003 8:19:00 AM	Copco 21	15	0.38	5.60	36XX - Electrical Systems
1346	02/18/2003 11:55:00 AM	02/18/2003 1:00:00 PM	Copco 12	13	1.08	13.80	45XX - Generator/Exciter
1348	02/19/2003 8:03:00 AM	02/19/2003 8:21:00 AM	Copco 11	14	0.30	4.20	39XX - Controls/Communication
1349	02/20/2003 8:05:00 AM	02/20/2003 8:10:00 AM	Copco 21	15	0.08	1.20	39XX - Controls/Communication
1386	03/07/2003 3:54:00 AM	03/07/2003 4:31:00 AM	Copco 21	15	0.62	8.90	39XX - Controls/Communication
1387	03/07/2003 4:07:00 AM	03/07/2003 4:42:00 AM	Copco 22	15	0.58	8.50	39XX - Controls/Communication
1388	03/09/2003 4:02:00 AM	03/09/2003 8:40:00 AM	Copco 11	14	4.63	64.90	39XX - Controls/Communication
1391	03/13/2003 5:41:18 AM	03/13/2003 9:26:00 AM	J.C. Boyle 1	45	3.75	168.80	36XX - Electrical Systems
1392	03/13/2003 6:22:03 AM	03/13/2003 6:34:00 AM	Copco 22	15	0.20	2.90	38XX - Auxiliary Systems
1403	03/15/2003 3:44:00 PM	03/17/2003 1:54:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	46.17	106.20	39XX - Controls/Communication
1407	03/19/2003 9:52:00 AM	03/21/2003 10:00:00 AM	J.C. Boyle 1	45	48.13	2,166.00	36XX - Electrical Systems
1408	03/19/2003 9:52:00 AM	03/19/2003 10:14:00 AM	J.C. Boyle 2	42	0.37	15.40	36XX - Electrical Systems
1412	03/26/2003 2:04:16 PM	03/28/2003 2:00:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	47.93	110.20	36XX - Electrical Systems
1413	03/26/2003 1:10:00 PM	03/27/2003 12:00:00 PM	Fall Creek 1	1	22.83	13.70	38XX - Auxiliary Systems

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1439	02/10/2003 8:00:00 AM	02/10/2003 12:00:00 PM	J.C. Boyle 1 J.C. Boyle 2	87	4.00	348.00	71XX - Water Delivery System
1440	01/27/2003 8:00:00 AM	01/27/2003 12:30:00 PM	J.C. Boyle 1 J.C. Boyle 2	87	4.50	391.50	71XX - Water Delivery System
1445	03/30/2003 12:00:00 PM	04/03/2003 12:00:00 PM	West Side	1	96.00	57.60	45XX - Generator/Exciter
1447	04/08/2003 2:00:00 PM	04/08/2003 2:15:00 PM	West Side	1	0.25	0.20	45XX - Generator/Exciter
1450	04/12/2003 12:20:00 AM	04/12/2003 1:20:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	13.00	29.90	45XX - Generator/Exciter
1456	04/13/2003 4:00:00 PM	04/13/2003 5:20:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	1.33	3.10	39XX - Controls/Communication
1457	04/13/2003 6:20:00 PM	04/14/2003 11:30:00 AM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	17.17	39.50	38XX - Auxiliary Systems
1460	04/14/2003 2:20:00 PM	04/14/2003 5:30:00 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	3.17	7.30	36XX - Electrical Systems
1496	05/06/2003 10:10:51 AM	05/06/2003 10:26:51 AM	Copco 22	0	0.00	0.00	99XX - Personnel Error
1513	05/15/2003 10:39:55 AM	05/15/2003 12:52:06 PM	Iron Gate	19	2.20	41.40	99XX - Personnel Error
1513	05/15/2003 10:39:55 AM	05/15/2003 12:52:06 PM	Iron Gate	19	2.20	41.40	99XX - Personnel Error
1522	05/21/2003 6:30:25 AM	05/21/2003 7:35:25 AM	Copco 21	15	1.08	15.70	39XX- Controls/ Communication
1529	05/28/2003 5:40:09 AM	05/28/2003 6:24:09 AM	Copco 11	14	0.73	10.30	45XX - Generator/Exciter
1534	05/29/2003 5:00:11 AM	05/29/2003 5:43:11 AM	Copco 22	15	0.72	10.40	38XX - Auxiliary Systems
1541	06/4/2003 2:30:00 PM	06/6/2003 10:30:00 AM	West Side	1	44.00	26.40	45XX - Generator/Exciter
1550	06/10/2003 7:55:06 AM	06/10/2003 8:08:06 AM	Copco 22	15	0.22	3.10	36XX - Electrical Systems
1551	06/12/2003 8:04:36 AM	06/12/2003 8:49:36 AM	Copco 11	14	0.60	8.40	39XX-Controls/ Communication
1614	07/5/2003 4:27:38 PM	07/5/2003 4:44:38 PM	Copco 11	14	0.28	4.00	39XX-Controls/ Communication
1628	07/13/2003 5:57:31 PM	07/13/2003 6:16:31 PM	Copco 22	15	0.32	4.60	36XX - Electrical Systems

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1647	07/25/2003 6:17:47 PM	07/25/2003 8:00:47 PM	Copco 11 Copco 12 Copco 21 Copco 22	56	1.72	95.60	93XX - External Problems
1648	07/25/2003 6:17:47 PM	07/25/2003 9:00:47 PM	Fall Creek 1 Fall Creek 2 Fall Creek 3	2	2.72	6.20	93XX - External Problems
1649	7/25/2003 6:17:24 PM	07/25/2003 10:30:24 PM	Iron Gate	19	4.22	79.30	93XX - External Problems
1665	08/3/2003 8:05:54 AM	08/5/2003 1:20:18 PM	J.C. Boyle 2	42	53.23	2,235.80	38XX - Auxiliary Systems
1683	08/17/2003 1:31:18 PM	08/17/2003 1:52:18 PM	Copco 11	14	0.35	4.90	39XX- Controls/Communication
1729	09/4/2003 11:43:52 AM	09/4/2003 1:30:52 PM	Fall Creek 1 Fall Creek 3	2	1.78	3.20	93XX - External Problems
1738	09/5/2003 7:25:15 AM	09/5/2003 8:25:15 AM	J.C. Boyle 1	45	1.00	45.00	39XX- Controls/Communication
1762	09/19/2003 9:00:21 AM	09/24/2003 12:00:06 PM	Fall Creek 3	1	123.00	147.60	70XX - Turbine
1766	09/19/2003 12:00:05 PM	09/30/2003 1:20:33 PM	Fall Creek 2	1	265.33	132.70	70XX - Turbine
1785	10/11/2003 10:02:47 AM	10/11/2003 10:16:47 AM	Copco 21	15	0.23	3.40	36XX - Electrical Systems
1788	10/12/2003 12:54:57 PM	10/13/2003 4:30:37 PM	J.C. Boyle 2	42	27.60	1,159.20	39XX- Controls/Communication
1790	10/10/2003 8:30:31 AM	10/10/2003 12:23:31 PM	Fall Creek 2 Fall Creek 3 Fall Creek 1	2	3.88	8.90	39XX- Controls/Communication
1795	10/16/2003 9:00:59 AM	10/16/2003 5:33:46 PM	Copco 21	15	8.55	124.00	36XX - Electrical Systems
1803	10/20/2003 10:10:25 AM	10/20/2003 3:40:25 PM	East Side	3	5.50	17.60	38XX - Auxiliary Systems
1815	11/2/2003 7:00:50 AM	11/2/2003 1:48:37 PM	Copco 22	15	6.80	98.60	45XX - Generator/Exciter
1836	11/11/2003 6:02:50 AM	11/11/2003 6:17:50 AM	Copco 21	0	0.00	0.00	39XX- Controls/Communication
1837	11/12/2003 6:50:44 AM	11/12/2003 7:12:38 AM	Copco 11	14	0.00	0.00	36XX - Electrical Systems
1840	11/12/2003 2:10:11 AM	11/12/2003 12:55:11 PM	J.C. Boyle 1	45	10.75	483.80	39XX- Controls/Communication
1845	11/3/2003 5:07:52 PM	11/10/2003 6:21:52 PM	West Side	1	169.23	101.50	70XX - Turbine
1860	11/20/2003 6:15:03 AM	11/20/2003 6:30:03 AM	Copco 22	15	0.25	3.63	36XX - Electrical Systems
1867	11/26/2003 8:11:26 AM	11/26/2003 10:23:26 AM	J.C. Boyle 1	45	2.2	99	38XX - Auxiliary Systems

Table H6.0-1. Klamath outages 2001 through 2003.

Outage Number	Outage Start (Date/Time)	Outage End (Date/Time)	Units	Total Unit Capacity (MW)	Duration (Hours)	Potential Lost Generation (MWh)	Cause
1874	12/3/2003 10:21:25 AM	12/9/2003 2:45:35 PM	West Side	1	148.40	89.00	70XX - Turbine
1876	12/4/2003 9:00:56 AM	12/4/2003 10:07:56 AM	Copco 11 Copco 12	27	1.12	29.80	39XX- Controls/Communication
1889	12/12/2003 4:32:10 AM	12/12/2003 5:00:10 AM	Copco 12	15	0.47	6.82	39XX- Controls/Communication
1891	12/12/2003 1:34:27 PM	12/12/2003 2:21:27 PM	J.C. Boyle 2	42	0.78	32.76	93XX - External Problems
1892	12/13/2003 4:58:14 AM	12/13/2003 5:04:14 AM	Copco 21	15	0.1	1.45	39XX- Controls/Communication
1894	12/15/2003 4:50:10 AM	12/15/2003 5:03:10 AM	Copco 21	15	0.22	3.19	39XX- Controls/Communication
1900	12/19/2003 5:05:02 AM	12/19/2003 5:52:59 AM	Copco 21	15	0.8	11.6	36XX - Electrical Systems
1902	12/21/2003 5:08:31 AM	12/21/2003 6:39:03 AM	Copco 22	15	1.52	22.04	39XX- Controls/Communication
1904	12/23/2003 5:20:01 AM	12/23/2003 5:36:31 AM	Copco 22	15	0.28	4.06	39XX- Controls/Communication

Prior to 2001, outage reporting was recorded in hand-written power logbooks, which did not include the same reporting procedures. Outages reported for the period prior to 2001 are grouped by powerhouse unit, outage time, and total potential lost generation for the year (Table H6.0-2). Actual outage occurrences are expected to have been fewer than shown owing to unrecorded maintenance events and load shifting to accommodate for water availability. All calculations for lost generation are based on turbine nameplate rating (maximum unit MW) and not on actual generation being produced at the time of the outage. Using the nameplate rating likely overestimates the lost generation.

Table H6.0-2. Summary of outages for period 1992 to 2000.

Year	Unit	Unit Capacity (MW)	Total Outage Hours	Potential Lost Generation (MW)
1992	Boyle #1	40	0	0
1992	Boyle #2	40	81.03	3241.2
1992	Copco #11	10	1458.18	14581.8
1992	Copco #12	10	216	2160
1992	Copco # 21	13.5	15	202.5
1992	Copco #22	13.5	370.26	4998.5
1992	East Side	3.2	1162.74	3720.8
1992	Fall Creek #1	0.5	8760	4380
1992	Fall Creek #2	0.45	18.18	8.2
1992	Fall Creek #3	1.25	18.18	22.7
1992	Iron Gate	18	15.5	279
1992	West Side	0.6	8784	5270.4
1993	Boyle #1	40	431.42	17256.8
1993	Boyle #2	40	105.24	4209.6
1993	Copco #11	10	177.22	1772.2
1993	Copco #12	10	210.5	2105
1993	Copco # 21	13.5	78.3	1057.1
1993	Copco #22	13.5	1027.45	13870.6
1993	East Side	3.2	306.41	980.5
1993	Fall Creek #1	0.5	2222.24	1111.1
1993	Fall Creek #2	0.45	13.36	6
1993	Fall Creek #3	1.25	13.36	16.7
1993	Iron Gate	18	1	18
1993	West Side	0.6	3743.45	2246.1
1994	Boyle #1	40	0	0
1994	Boyle #2	40	0	0
1994	Copco #11	10	34	340
1994	Copco #12	10	1449	14490
1994	Copco # 21	13.5	15.55	209.9
1994	Copco #22	13.5	278.7	3762.5
1994	East Side	3.2	27.35	87.5
1994	Fall Creek #1	0.5	14.62	7.3

Table H6.0-2. Summary of outages for period 1992 to 2000.

Year	Unit	Unit Capacity (MW)	Total Outage Hours	Potential Lost Generation (MW)
1994	Fall Creek #2	0.45	14.12	6.4
1994	Fall Creek #3	1.25	0	0
1994	Iron Gate	18	0	0
1994	West Side	0.6	5728.35	3437
1995	Boyle #1	40	0.48	19.2
1995	Boyle #2	40	27.51	1100.4
1995	Copco #11	10	20.56	205.6
1995	Copco #12	10	75.61	756.1
1995	Copco # 21	13.5	13.05	176.2
1995	Copco #22	13.5	152.14	2053.9
1995	East Side	3.2	2955.55	9457.8
1995	Fall Creek #1	0.5	0	0
1995	Fall Creek #2	0.45	0	0
1995	Fall Creek #3	1.25	0	0
1995	Iron Gate	18	0.56	10.1
1995	West Side	0.6	1783.54	1070.1
1996	Boyle #1	40	74.52	2980.8
1996	Boyle #2	40	121.89	4875.6
1996	Copco #11	10	700.2	7002
1996	Copco #12	10	2843	28430
1996	Copco # 21	13.5	31.28	422.3
1996	Copco #22	13.5	12.7	171.5
1996	East Side	3.2	4.97	15.9
1996	Fall Creek #1	0.5	40.78	20.4
1996	Fall Creek #2	0.45	0.62	0.3
1996	Fall Creek #3	1.25	0.74	0.9
1996	Iron Gate	18	8.42	151.6
1996	West Side	0.6	1767.02	1060.2
1997	Boyle #1	40	5	200
1997	Boyle #2	40	6	240
1997	Copco #11	10	120.96	1209.6
1997	Copco #12	10	1.46	14.6
1997	Copco # 21	13.5	11.69	157.8
1997	Copco #22	13.5	1164.3	15718.1
1997	East Side	3.2	122.38	391.6
1997	Fall Creek #1	0.5	78.89	39.4
1997	Fall Creek #2	0.45	194.1	87.3
1997	Fall Creek #3	1.25	3582.08	4477.6
1997	Iron Gate	18	3.36	60.5
1997	West Side	0.6	0	0

Table H6.0-2. Summary of outages for period 1992 to 2000.

Year	Unit	Unit Capacity (MW)	Total Outage Hours	Potential Lost Generation (MW)
1998	Boyle #1	40	67.87	2714.8
1998	Boyle #2	40	405.02	16200.8
1998	Copco #11	10	40.02	400.2
1998	Copco #12	10	104.88	1048.8
1998	Copco # 21	13.5	298.64	4031.6
1998	Copco #22	13.5	39.98	539.7
1998	East Side	3.2	188.1	601.9
1998	Fall Creek #1	0.5	12.18	6.1
1998	Fall Creek #2	0.45	12	5.4
1998	Fall Creek #3	1.25	12	15
1998	Iron Gate	18	0.18	3.2
1998	West Side	0.6	1212.26	727.4
1999	Boyle #1	40	18.5	740
1999	Boyle #2	40	0	0
1999	Copco #11	10	0	0
1999	Copco #12	10	0	0
1999	Copco # 21	13.5	3	40.5
1999	Copco #22	13.5	0	0
1999	East Side	3.2	301.9	966.1
1999	Fall Creek #1	0.5	0	0
1999	Fall Creek #2	0.45	0	0
1999	Fall Creek #3	1.25	0	0
1999	Iron Gate	18	0	0
1999	West Side	0.6	1684.78	1010.9
2000	Boyle #1	40	0.2	8
2000	Boyle #2	40	0.4	16
2000	Copco #11	10	0	0
2000	Copco #12	10	0.42	4.2
2000	Copco # 21	13.5	0	0
2000	Copco #22	13.5	0	0
2000	East Side	3.2	10.5	33.6
2000	Fall Creek #1	0.5	0	0
2000	Fall Creek #2	0.45	0	0
2000	Fall Creek #3	1.25	0	0
2000	Iron Gate	18	0	0
2000	West Side	0.6	24	14.4

H7.0 LICENSE COMPLIANCE RECORD

To report the company's compliance record with the current Project license, PacifiCorp reviewed relevant correspondences from FERC for the period 1993 to 2003. Since 1993, FERC has noted only one incidence of noncompliance with the Project FERC license (Table H7.0-1).

Table H7.0-1. Violation of FERC license for Klamath Hydroelectric Project (1993–2002).

Date	Violation
July 1, 2000	River elevation below the J.C. Boyle powerhouse exceeded the maximum rate of change. No recommendations of enforcement action or penalties were given. (letter to R. Landolt, PacifiCorp, from G. Taylor, FERC, on October 20, 2000)

PacifiCorp continues to operate and to complete efforts that strive toward compliance with the requirements of the current license. Where violations have occurred, the company is taking corrective action toward eliminating any future noncompliance events.

H7.1 ACTIONS AFFECTING THE PUBLIC

PacifiCorp has satisfied all state and federal guidelines for dam safety. PacifiCorp has also developed an Emergency Action Plan to provide downstream warning to the public in case of an emergency. Additional recreation sites have been constructed to the benefit of the public outside of the license requirements. These sites include fishing accesses Nos. 1 – 6 on the Klamath River between J.C. Boyle and Copco power facilities, and Jenny Creek and Long Gulch day use/ camping areas on Iron Gate reservoir (see the Recreation Resources section of Exhibit E in the final license application).

H7.2 STATEMENT OF MEASURES TAKEN OR PLANNED TO ENSURE SAFE MANAGEMENT, OPERATION, AND MAINTENANCE OF THE PROJECT

PacifiCorp's Hydro Resources Department has a safety plan that is followed to ensure safe management, operation, and maintenance of the Project. The purpose of the Hydro Resources safety plan is to define the programs and processes that are to be used by Hydro Resources to provide a workplace that is free of physical hazards and to promote safe work practices. The department strives to provide a workplace that encourages communication concerning safety-related issues between employees as a group and between individual employees and management. Hydro Resources will constantly strive to improve safety in all of the business process that it conducts. The following sections describe the various components of the safety program and plan.

H7.2.1 Management Responsibility

Hydro Resources production managers are ultimately responsible for the functioning of the safety program. The production manager is responsible for making sure that the safety programs are implemented and all safety rules are followed.

H7.2.2 Employee Responsibility

Each employee is responsible for knowing and following all safety procedures and policies that have been established for safe work practices. Employees who choose to disregard safety policies and procedures will be subject to PacifiCorp disciplinary policies. The purpose of using the disciplinary process is to change safety behaviors for an individual and a group.

H7.2.3 Safety Committees

Safety committees will be used in all areas to assist with accident investigations, direct meetings, and facilitate communication between management and union employees.

H7.2.4 Training

Hydro Resources will conduct training for all required OSHA programs each year. Required training will be conducted as required by law. Additional training on subjects that will complement the employees present work activities will be provided.

H7.2.5 Safety Meeting

Safety meetings will be conducted in all areas each month. The safety committee members will direct safety meetings. Safety meetings will be used to discuss the status of safety work orders, hazardous conditions, and MSDS sheet reviews, among other topics.

H7.2.6 Accident Investigation

Hydro Resources will have an accident management system for accident and near miss investigations. Each accident will be investigated; the circumstances surrounding an accident will be used to determine the depth of the investigation. Accident reviews will include root cause analysis and recommendations to prevent reoccurrence of the accident. Accident investigation teams will include management and union employees that have been trained in effective accident investigation procedures.

H7.2.7 Programs

Hydro Resources will ensure that required safety programs and training are provided for all employees.

H7.2.8 Visual Plant

To promote a safe work place and to aid in the operating of the power plants, Hydro Resources will follow the Hydro Visual Plant Standard for all plants.

H7.2.9 Personal Protective Equipment

Personal protective equipment will be used in accordance with Hydro Hazard assessments. All PacifiCorp employees and contractors are expected to be knowledgeable of the hazard assessments and to follow the hazard assessment that has been established for the Project area. Visitors will follow the visitor safety policy when visiting sites.

H7.2.10 Safety Audits

Production managers will conduct quarterly safety inspections in their areas of responsibility each quarter. Members of management and safety committee members will conduct inspections. Results of the inspections will be communicated to the safety administrator and employees of the area. Every effort will be made to address each safety concern. Serious concerns will be addressed immediately.

Safety program reviews will be conducted at regular intervals to assess the effectiveness of Hydro Resource safety programs. A safety compliance audit will be conducted annually.

H7.2.11 Contractor Safety

Hydro Resources will follow the PacifiCorp Contractor policy when contracting with outside contractors. Contractor's work standards will conform to the minimum OSHA standards and to any additional requirements of PacifiCorp.

H7.3 STATEMENT OF ANNUAL FEES PAID FOR USE OF FEDERAL OR INDIAN LANDS

Portions of the existing Project are located on federal lands (Keno facilities are partially on USBR land and J.C. Boyle facilities are partially on BLM land). Annual fees are paid under Part I of the Federal Power Act to these two entities. For bill year 2003, PacifiCorp paid annual charges of $14,396.96. In the future license, with the exclusion of the Keno development, annual fee responsibility will be limited to federal lands located at the J.C. Boyle development and within the new FERC boundary.

H7.4 INFORMATION SOURCES

Oregon Water Resources Department. 2002. Personal communication with T. Olson of PacifiCorp. October 29, 2002.