Swift No. 1 Hydroelectric Project
FERC Project No. 2111

FINAL LICENSE APPLICATION

Exhibit H – Applicant's Qualifications to Operate the Project

PacifiCorp
Portland, Oregon

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TABLE OF CONTENTS

H.1.0 INTRODUCTION....................1

H.2.0 APPLICANT'S QUALIFICATIONS TO OPERATE THE PROJECT....................1

H.2.1 COMPANY....................1
H.2.2 PROJECT OVERVIEW....................1
H.2.3 FINANCIAL RESOURCES....................4

H.3.0 NEED FOR PROJECT ELECTRIC GENERATION....................4

H.3.1 PACIFICORP'S INTEGRATED RESOURCE PLANNING PROCESS...4
H.3.1.1 Action Plan....................6
H.3.1.2 Renewable Resources....................7
H.3.1.3 Flexible Resources....................7
H.3.1.4 Additional Long-Term Resources....................8
H.3.1.5 Shaped Products and Power Purchase Agreements....................8
H.3.2 DEMAND-SIDE MANAGEMENT....................8
H.3.3 ENERGY AND COST IMPLICATIONS OF LICENSE DENIAL..........10

H.4.0 ALTERNATIVE POWER SOURCES....................15

H.4.1 CAPACITY AND ENERGY REQUIREMENTS....................15
H.4.2 COST OF ALTERNATIVE SOURCES OF POWER....................15
H.4.2.1 Natural Gas-fired Resources....................16
H.4.2.2 Cogeneration....................16
H.4.2.3 Wind....................17
H.4.2.4 Coal....................17
H.4.3 PURCHASING MARKET POWER....................18
H.4.4 PLANS TO MODIFY PROJECT FACILITIES AND OPERATION......18

H.5.0 INDIAN TRIBES POTENTIALLY AFFECTED BY THE PROJECT.........19

H.6.0 HISTORICAL AND DAILY PROJECT OPERATION....................19

H.6.1 PROJECT OPERATION....................19
H.6.2 PROJECT OPERATION DURING FLOOD CONDITIONS....................21
H.6.3 PROJECT SAFETY....................21
H.6.4 RECORD OF PROJECT HISTORY....................22
H.6.5 PROJECT OUTAGES....................22
H.6.6 STATEMENT OF LICENSE COMPLIANCE....................25

H.8.0 LITERATURE CITED....................27

LIST OF FIGURES

Figure H.2.2-1. Lewis River Hydroelectric Projects Area Map 2
Figure H.3.3-1. Transmission Network Diagram Sheet 1 13
Figure H.3.3-2. Transmission Network Diagram Sheet 2 13

LIST OF TABLES

Table H.3.2-1. DSM Programs Operating During 2003. 8
Table H.4.1-1. Total forecasted energy and peak load requirements for the PacifiCorp system. 15
Table H.6.5-1. Swift No. 1 Project Outages (January 1, 2001 – May 21, 2003) 23
Table H.6.5-2. Swift No. 1 Project Outages (January 1, 1998 – December 31, 2000) 25

H.1.0 INTRODUCTION

In compliance with the Code of Federal Regulations (18 CFR, Parts 4 and 16), PacifiCorp is applying to the Federal Energy Regulatory Commission (FERC) to relicense the Swift No. 1 Hydroelectric Project (FERC Project No. 2111) on the North Fork Lewis River, in the State of Washington. The current license for the Swift No. 1 Project, which PacifiCorp currently owns and operates, was issued on October 29, 1956 and expires on May 1, 2006.

PacifiCorp is applying for a new license to continue operation of the Swift No. 1 Project. This Exhibit H presents the response to information required by the FERC as described in 18 Code of Federal Regulations (CFR) Section 16.10(a) and (b).

Following this introduction, Section H.2.0 describes the applicant's ability to operate the Swift No. 1 project. Section H.3.0 discusses the need for Swift No. 1 Project power, and Section 4.0 provides data describing alternative power sources. Section H.5.0 describes PacifiCorp's electricity consumption efficiency improvement program. Section H.6.0 lists Indian tribes potentially affected by the Swift No. 1 Project. Finally, Section H.7.0 provides information on Swift No. 1 operations.

H.2.0 APPLICANT'S QUALIFICATIONS TO OPERATE THE PROJECT

H.2.1 COMPANY

PacifiCorp owns and operates 51 hydroelectric plants and serves as operator for 2 additional projects. These facilities are located throughout several states including Oregon, Washington, California, Idaho, Utah, and Montana. The projects contain a total of 91 turbine generator units, representing 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.

All Hydro Resources Department personnel attend periodic safety and training programs. Staff located in the Portland office attend monthly safety meetings. In addition, staff refresh their skills by attending additional training courses provided by the Company. Staff located at the Lewis River Projects attend monthly safety and training meetings.

H.2.2 PROJECT OVERVIEW

The Swift No. 1 Project is one of 3 PacifiCorp hydroelectric projects located on the North Fork of the Lewis River, approximately 28 miles east of Woodland, Washington and 53

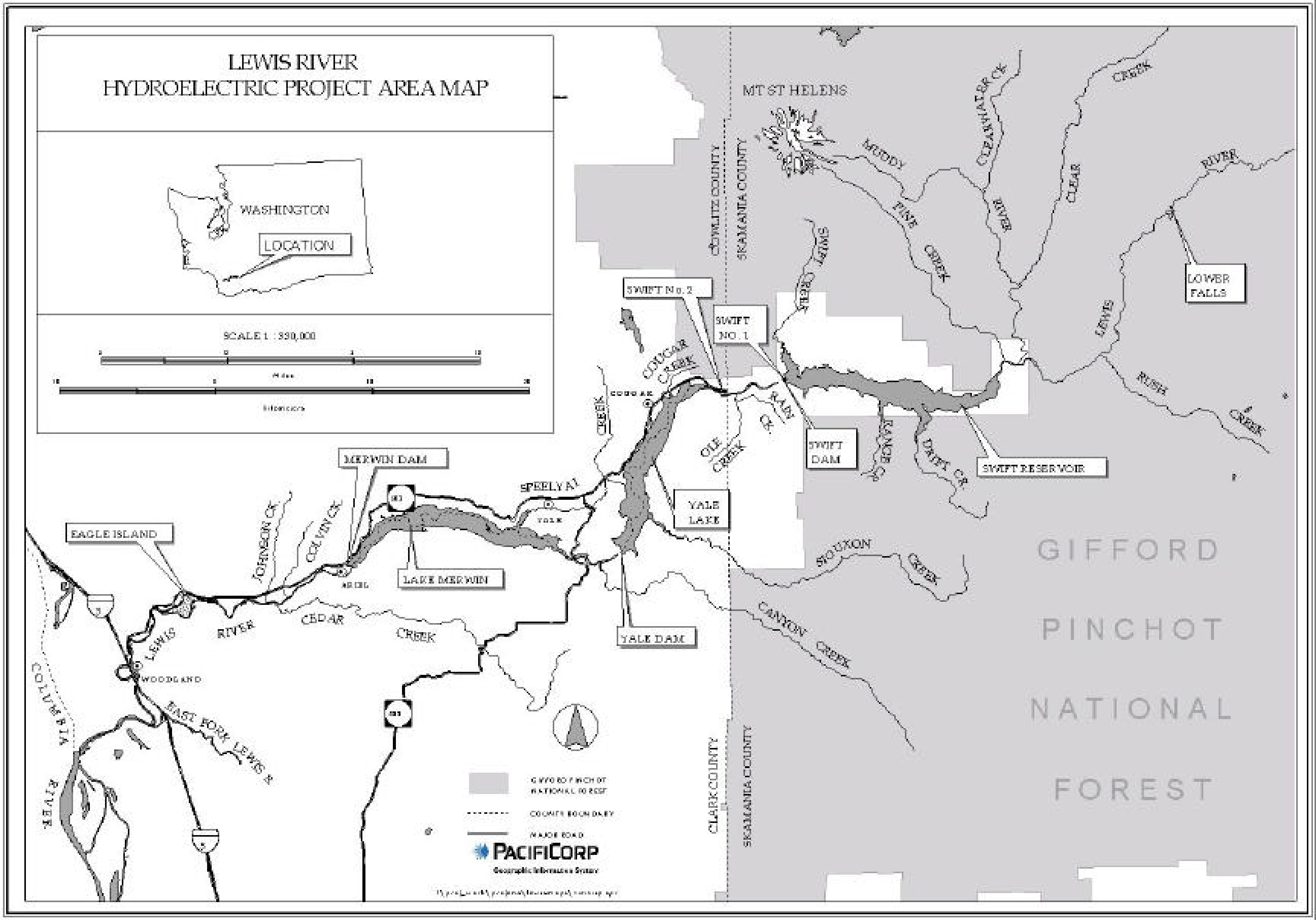

Figure H.2.2-1. Lewis River Hydroelectric Projects Area Map

miles northeast of Portland, Oregon. The site is about 40 miles upstream of the confluence of the North Fork Lewis River with the Columbia River. Located at RM 47, the Swift No. 1 Project is the last in a string of 4 facilities on the Lewis River. The other 3 projects are Yale (FERC Project No. 2071), Merwin (FERC Project No. 935), and Swift No. 2 (FERC Project No. 2213). Yale is located at RM 34, Swift No. 2 is located at RM 44, and Merwin is located at RM 19.5. Merwin, Yale and Swift No. 1 are owned and operated by PacifiCorp. Swift No. 2 is owned by the Cowlitz County Public Utility District No. 1 (Cowlitz PUD) and maintained and operated by PacifiCorp under contract. The Swift No. 1 Project location within the North Fork Lewis River drainage basin is shown on Figure H.2.2-1.

The Swift No. 1 Project is operated as a flexible and load following facility and to meet reservoir storage requirements, system load and recreational needs. Storage from Swift Reservoir is also released downstream as necessary to meet the Merwin License Article 49 minimum flow requirements.

PacifiCorp is the major private landowner with about 3,100 acres in the Swift No. 1 Project vicinity. Other adjacent lands in public ownership are managed by the Bureau of Land Management (BLM), the U.S. Forest Service (USFS), and the State of Washington, and Clark County. PacifiCorp pays approximately $18,000 annually in land use fees for the Swift No. 1 Project to the FERC.

PacifiCorp is continually examining ways to improve plant operations and increase generation at its power plants. In 1996, a Generation Capability Assessment study was commissioned to assess the current condition and investigate the potential for upgrades to the Merwin, Yale and Swift No.1 generation facilities (Appendix F). The focus of this study was to identify areas with the greatest potential for improvements to efficiently use the available water resource and improve the project's capability. The study evaluated the current operational regime, water delivery system, hydraulic turbines, generators, generator buses, and transformers. Results of the study identified various upgrades to civil, mechanical, and electrical systems that have the potential to improve the project's operation.

The results of the study have been evaluated by PacifiCorp and are being used as a basis for the development of conceptual plans involving upgrades to the existing turbine generator units and associated equipment. These plans are focused to better meet the Company's future needs for energy, and to respond to changes in a variety of operational factors that include environmental, recreation and safety aspects in a cost-effective, balanced manner. Consequently, the Company is considering several plans for upgrades to the Lewis River Projects. Potential Swift No. 1 improvements would involve the installation of more modern hydraulic turbine runners in the existing turbine generators to increase unit efficiency and capacity, and associated equipment improvements to support the unit upgrades. It is possible that some of these improvements could happen within the first 5 years of new license issuance and involve a non-capacity license amendment.

PacifiCorp will continue to evaluate the opportunity for further project upgrades and/or modifications as future market and operational conditions/requirements change, with the purpose of ensuring the most cost-effective, efficient and environmentally balanced use of the water resources available.

Continued operation of the Swift No. 1 Project, as proposed in this License Application, is the best plan for developing the waterway as stated in Section 10(a)(1) of the Federal Power Act. The application represents a cost-effective, efficient, and environmentally balanced use of the water resources of the Lewis River.

H.2.3 FINANCIAL RESOURCES

PacifiCorp is a utility with broad experience in the construction, operation, and maintenance of hydroelectric projects. Its sources of financing and annual revenues are adequate to meet the continuing operation and maintenance needs of the Swift No. 1 Project. 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, filed with the Federal Energy Regulatory Commission on April 30, 2003.

H.3.0 NEED FOR PROJECT ELECTRIC GENERATION

H.3.1 PACIFICORP'S INTEGRATED RESOURCE PLANNING PROCESS

On a periodic basis, PacifiCorp completes a comprehensive analysis of future load growth, the ability of existing resources to meet customers' electric energy service needs, and the need for new resources, including customer energy efficiency programs. This process, referred to as the Integrated Resource Plan (IRP), provides a framework for prudent future actions required to ensure that PacifiCorp can continue to provide reliable and least-cost electric service to its customers. Recently, more than 30 IRP 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 future resource 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.

Through its short-term and long-term time planning, PacifiCorp strives to:

- Deliver the most economic solution in meeting its load service obligations;
- Reduce commodity risk;
- Serve load with a diverse portfolio that includes both owned assets and purchases; and
- Reduce cost and risk with hedges and load management programs.

As such, the IRP serves as 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 (natural gas and electricity) 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 impact to overall net power cost. Furthermore, unpredictability in the future costs of new supply alternatives arising from gas price and emissions, 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 expected future needs 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 its 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 needs of current customers, requirements for new customers, and potential increased requirements for supply reserves. The total needs would increase the company's resource portfolio by about 40 percent of current levels, including long-term purchases, by 2014. In addition, the IRP considers expected lost capacity resulting from aging plants, reduced output, and expiring supply contracts. PacifiCorp's resource needs are focused on meeting its obligation to meet the growing 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 resource and transmission rights. This methodology provides an examination of both the expected future costs and the risks of future outcomes. It also allows an examination of the risks inherent in resource planning choices and allowed the choice of the least cost portfolio. This is in contrast to PacifiCorp's previous 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, since 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 & 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 because PacifiCorp operates its system on an integrated basis.

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; and
- Discussion on the action plan's consistency with Oregon's restructuring legislation (SB-1149).

This Action Plan is further summarized below.

H.3.1.1 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 both demand-side and supply-side (new resources) management. The Resources in the Diversified Portfolio I include:

- Up to 450 average MW of demand-side management (DSM) programs;
- 1,400 MW of renewable resources;
- 2,100 MW of resources that may operate continuously
- 1,200 MW of flexible resources that can be available to help achieve load/resource balance during periods of high demand;
- 700 MW of shaped resources – contracts or resources that fill specific needs

PacifiCorp's DSM programs are described in Section 5.0 below. The remaining parts of the Diversified Portfolio I are described in Sections H3.1.2 through H3.1.5.

H.3.1.2 Renewable Resources

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/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 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.

H.3.1.3 Flexible Resources

Diversified Portfolio I anticipated a requirement for up to 1,200 MW of flexible resources to be added over the plan period 2006 to 2013. However, the IRP recognizes that the equipment market and economics at the time decisions are made will dictate the actual technology used. Flexible 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. The second, as anticipated by the IRP, is to meet the capacity requirements of a 15 percent planning margin.

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. Further study of an appropriate planning margin for PacifiCorp will continue, and is an element of the action plan. These resources may consist of power purchase agreements, facility leases, self-build alternatives, or a combination thereof.

H.3.1.4 Additional Long-Term Resources

In line with the load growth, plant retirement and contract expiration, an estimated 2,100 MW of additional long-term resources are expected to be required. Three new resources are expected for the East and one for the West.

These resources may consist of power purchase agreements, facility leases, self-build alternatives, or a combination thereof.

H.3.1.5 Shaped Products and Power Purchase Agreements

Diversified Portfolio I also anticipates the requirement of approximately 700 MW of customized power purchase agreements throughout the plan period 2004 to 2013. These contracts were anticipated by the IRP to fill an immediate short term need in the system.

H.3.2 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. The company-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 economic DSM programs as an effective means helping to meet its load service obligations. 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 H.3.2-1.

Table H.3.2-1. DSM Programs Operating During 2003.

DSM Program Name	Description	Availability
Energy FinAnswer (Schedule 125, enhanced with incentives)	Engineering & 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 & 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*

DSM Program Name	Description	Availability
Compact Fluorescent Light Bulb Program	Two free CFLs are offered to residential customers through direct mail offer. Provides immediate savings benefits and encourages CFL use.	ID*, WY*
Enhanced Audit and Weatherization Program	Residential in-home audit with customer choice of low interest loan or 25% rebate to assist in funding 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*
Low-Income Weatherization Program	The Company 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.
BPA Conservation and Renewable Discount Program	Credits received against PacifiCorp's BPA electricity purchases for incremental energy efficiency and renewable investments. Strategy will be created on how best to leverage these dollars to benefit the company and the communities served.	OR*, WA*, ID*
Energy Efficiency Education – Bright Ideas Booklet	Published booklet featuring residential energy use and efficiency information that is mailed to customers upon request. Available in English and Spanish.	CA, ID, OR, UT, WA, WY
Low Income Energy Education Services	Provides qualifying customers energy education and do-it-yourself instruction on how to reduce energy costs. Minimal direct installation assistance to qualifying senior citizens.	OR – Portland Area only
Efficient Air Conditioning Program	Provides customer incentives for improving the efficiency of air conditioning equipment and/or maintaining or converting air conditioning equipment to evaporative cooling technologies.	UT*, WA*
Energy Education to Schools	Provides classroom instruction to grade school and intermediate students on energy education.	WA (Lower Yakima Valley schools)
Low Income Conservation	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 1,636 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.	OR, WA, ID

DSM Program Name	Description	Availability
Commercial Retro Commissioning	Pilot program designed to work with customers to re-commission the operation of their commercial buildings consistent with the building was designed to operate.	UT
* Programs under evaluation.		

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

H.3.3 ENERGY AND COST IMPLICATIONS OF LICENSE DENIAL

PacifiCorp's current plan for meeting control are reliability requirements and retail customer demand includes the generation associated with the future FERC license of the Swift No. 1 Hydroelectric Project. Should this flexible resource be unavailable, its replacement would be required for both reliability and load service obligation purposes. The replacement cost of power lost from the project can be represented generally using PacifiCorp's current 34-year power cost projections. The annual levelized value of power over the next 34 years under current license operation, using a discount rate of 7.5 percent, is estimated to be between $44 and $66.

Given the numerous influential variables, it is challenging to quantitatively evaluate the consequences of license denial. Two broad consequences are discussed below: the impact of license denial on PacifiCorp customers, and the impact of license denial on the local environment of the Swift No. 1 Hydroelectric Project site.

Power generated on the Lewis River is part of PacifiCorp's overall portfolio. Without the local generation, PacifiCorp would be required to acquire replacement power and integrate the new resource into PacifiCorp's system. Integration costs for a new resource would depend upon its location and connection to the electric grid. It would be highly unlikely that a new resource could be integrated without incurring transmission wheeling costs, which could be significant if interconnection is across congested paths.

Other benefits that would be lost are those resulting from the flexible nature of the resource. More so than any other production facility in its portfolio, PacifiCorp, as the Lewis River operator, relies heavily on utilizing the project's generation flexibility in meeting its reliability obligations as the operator of two electrical control areas. The flexibility afforded by the projects on the Lewis River, when operated in a coordinated, safe, and environmentally prudent fashion, help enable PacifiCorp to: 1) meet moment-to-moment changes in load demand within two control areas of the North American Electric Reliability Council (NERC); 2) provide operating reserve capacity to maintain electric grid voltage and frequency in the event of the loss of generation or critical transmission elsewhere on the grid; 3) managing inadvertent interchange with other electrical control areas; 4) minimizing the exposure of its ratepayers to financial impacts of power price volatility; 5) maximizing its ability to dispatch fossil fuel plant units at maximum economy to its ratepayers and to minimize fossil fuel consumption by running thermal units at maximum efficiency unit loadings; and 6) firming up and making useful the generation from intermittent resources such as wind turbines.

Additionally, in the event of license denial, PacifiCorp would be required to undertake transmission and distribution system reinforcement projects in the local area to compensate for the lost power supply and voltage control provided by the project. Figures 3.3-1 and 3.3-2 show the transmission system serving the area supported by the project.

Public use of project lands has resulted in potential resource conflicts and impacts on cultural, biological and other resources. PacifiCorp's license application includes a number of proposals to improve current conditions and provide a balanced use of resources in the project area. If PacifiCorp's license application is denied, or if operations are continued under current conditions (annual) license, none of these measures will be implemented, resulting in potential resource degradation.

License denial could also result in competition for the license. Competition would delay licensing, thereby forestalling the proposed project improvements and enhancement measures. Finally, denial of the license application could lead to decommissioning of the project. While this scenario is unlikely, such an action would have significant cost implications to PacifiCorp customers and investors.

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Figure H.3.3-1. Transmission Network Diagram Sheet 1

Figure H.3.3-2. Transmission Network Diagram Sheet 2

The Federal Energy Regulatory Commission issued Order No. 630 on February 21, 2003. That Order provides guidelines on material that can be classified as Critical Energy Infrastructure Information (CEII) and should be filed with the Commission as confidential information pursuant to 18 CFR 388.112. Therefore, we are not providing a copy of Figure H.3.3-1 the Transmission Network Diagrams for the Oregon/California area due to its potentially sensitive nature.

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H.4.0 ALTERNATIVE POWER SOURCES

H.4.1 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 4 percent of PacifiCorp's retail sales are to industrial customers, about 11 percent are to commercial customers and about 85 percent are to residential.

In calendar year 2002, PacifiCorp's retail system energy requirements were 5,867 average megawatts (MWa). The winter and summer peak loads were 7,585 MW and 8,511 MW, respectively. PacifiCorp has more than 8,300 MW of generation capacity. About 68 percent of PacifiCorp's capacity comes from company-owned thermal and hydroelectric plants, and 32 percent from power purchases. PacifiCorp generally uses 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 H.4.1-1). The winter and summer coincidental peak load forecast for year 2011 range 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 H.4.1-1. 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 Western Electricity Coordinating Council Coordinating Council (WECC) and the Minimum Operating Reliability Criteria (MORC) guidelines. Operating reserves ensure day-to-day reliability. The guidelines identify spinning and non-spinning reserves. The WECC 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).

H.4.2 COST OF ALTERNATIVE 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 costs of alternate supply-side resources are presented in Table H.4.2-1. The replacement costs are specific to the Project and based on a future Project total generating capacity of 240 MW. The annual cost is based on an average annual Project generation of 631,988 MWh. This value is the total Project long-term (30-year) average generation, not including generation from Swift No. 2. Costs are developed annually by the PacifiCorp Hydro Resources Department.

Table H.4.2-1. Capital Cost of Alternate Supply-Side Resources

Source	$/kW	Project Replacement Cost$ ($ Millions)[1]	Estimated Annual O&M Cost for Replaced Project Power ($ Million)[2]
Natural Gas	697	167	25
Cogeneration	917	220	28
Wind	1,067	256	24
Coal	1,754	421	19
[1] Cost estimates derived from January 2003 IRP Appendix C Table c.18.			
2 Cost estimate includes the Project replacement costs			

H.4.2.1 Natural Gas-fired Resources

The most efficient 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 1 year needed for the necessary permits. Environmental impact is low, with the greatest problem being nitrogen oxide (NOx) emissions, but control technologies are available.

The advantages of a CCCT is the relatively low capital cost. When comparing to a non-natural gas fueled resource, such as a coal plant, the disadvantage of a CCCT is its higher fuel cost (the cost of fuel required for a CCCT to produce a kilowatt-hour (kWh) of electricity is greater than that of a coal plant). While natural gas-based resources, depending on their location, can have uncertainty over the future cost and supply of natural gas, other resources are more sensitive to uncertainty around other costs (emissions and system integration). 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 $167 million in capital to build a plant. Annual operations, including the cost of capital, would be an estimated $25 million per year.

H.4.2.2 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 $220 million in capital to build a plant. Annual operations, including the cost of capital, would be an estimated $28 million per year.

H.4.2.3 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-based resources include project scalability, often a minimum environmental impact, no fuel cost, and a comparatively short lead-time for construction.

Disadvantages of wind power include a low capacity factor and an intermittent energy source (i.e., energy gets produced only when the wind is blowing). Wind can also be a difficult resource to schedule than hydroelectric plants in that it requires the accurate prediction of where and when the wind will blow. Thus, resources can be an important component to a diversified portfolio but should not be viewed as a viable replacement alternative for a flexible resource such as those located along the Lewis River. Indeed, PacifiCorp's IRP anticipates the significant addition of renewable resources such as wind over the planning horizon. However, this IRP conclusion was reached based on an underlying assumption that PacifiCorp would have continued access to flexible hydro resources in order to assist in the reliable integration of intermittent renewable resources such as wind.

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 $256 million in capital to build a plant. Annual operations including the cost of capital would be an estimated $24 million per year.

H.4.2.4 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 coal technology that uses a coal gasification process to produce 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 resources 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 $421 million in capital. Annual operations, including the cost of capital, would be an estimated $19 million per year. However, the physical ability to directly transmit power from these studied projects to PacifiCorp's western control area does not currently exist and would likely result in additional material expense.

H.4.3 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 price projections that use a combination of market clearing price models and market data. 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 multiplied by the long-term (30-year) average on-peak and off-peak megawatt hours (MWh) that may be generated by the proposed Project under normal conditions.

The annual average value of power for the 30-year license period (starting in 2006) is estimated to be $70/MWh. The range around this estimate is from a low of $56/MWh to a high of $83/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 441,418 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 185,570 MW hours (proposed Project), is $15.6 million per year.

Market purchases, of course, would not replace the capabilities of the project with respect to helping PacifiCorp maintain the reliability and electrical integrity of the PacifiCorp control areas.

H.4.4 PLANS TO MODIFY PROJECT FACILITIES AND OPERATION

As part of this license application, PacifiCorp is not proposing any major modifications or upgrades. However, the Company will continue to evaluate the potential for project upgrades and modifications as future market and other conditions change, to ensure the most cost-effective, efficient and environmentally balanced use of the water resources available

H.5.0 INDIAN TRIBES POTENTIALLY AFFECTED BY THE PROJECT

The Merwin Project does not occupy any established Indian tribal reservation; however, two Pacific Northwest Indian Tribes have treaty-protected rights which may be affected by the Merwin Project. To keep the tribes informed on how the project may affect those protected rights, PacifiCorp consulted with the following Indian tribes or organizations:

Yakama Nation
PO Box 151
Toppenish, WA 98948

Cowlitz Indian Tribe
PO Box 2547
Longview, WA 98632

Consultation with the 2 tribes is described in Section 3.7 of the Preliminary Draft Environmental Assessment in volume 2 of this application.

H.6.0 HISTORICAL AND DAILY PROJECT OPERATION

H.6.1 PROJECT OPERATION

The Swift No. 1 Project is operated as a flexible and load following facility and to meet reservoir storage requirements, system load and recreational needs. Storage from Swift Reservoir is also released downstream as necessary to meet the Merwin License Article 49 minimum flow requirements.

The Swift No. 1 Project is one of the Lewis River Hydroelectric Projects that are operated as integral components of PacifiCorp's control areas. Scheduling of power resources is coordinated daily based on factors such as reservoir storage, fishery requirements, recreation requirements, flood control requirements, snow pack conditions, current and forecasted inflow conditions, system load requirements, availability of other resources, and in-stream flow requirements. Real-time adjustments to this schedule can and do occur as load and resource conditions dictate. Water releases for generation are based on the need for the dispatch of a flexible resource, real-time load demands, river and reservoir management objectives.

The Swift No. 1 units can be remotely operated and monitored from the Hydro Control Center (HCC) located at the Merwin headquarters building. These units can also be manually or automatically operated from the plant. The Swift Plant is visited several times daily as 3 operators are on duty for the entire Lewis River Hydroelectric Project during normal work hours. At all other times, 2 operators are on duty. Operators live in housing near Merwin powerhouse and are available for local control and on short notice. However, the powerhouse is generally operated and monitored from the Hydro Control Center (HCC) located at the Merwin headquarters building.

Water releases for generation are based on energy production, flexible, real-time load following, and river and reservoir management. HCC is staffed 24 hours a day with at least one operator per shift (Merwin Operator). Hourly generation for each plant is prescheduled by the C&T Operations Planning Group in Portland. The prescheduled generation is dispatched in real-time through coordination between HCC and the C&T Real Time Generation Control Desk, located in Portland. Swift units are then operated from HCC in one of three control modes, as follows:

<u>Local Manual Operation</u>: To start a unit on local manual, the operator verifies that the lube oil pump for the turbine guide bearing is operating and the bearing oil level is normal. The operator can then push the start button, and the unit will roll and come up to speed. Once up to speed, the operator turns on the synchroscope and manually synchronizes the unit to the line, and closes the breaker to connect the unit to the system. The output and voltage can then be adjusted manually as required by the Merwin or Swift operator.

<u>Local Auto Operation</u>: To start a unit on local auto, the operator verifies that the lube oil pump for the turbine guide bearing is operating and the bearing oil level is normal. The operator can then push the start button, and the unit will roll, come up to speed, synchronize, and close the breaker automatically. The output and voltage can then be adjusted by the Merwin or Swift operator.

<u>Remote Auto Operation</u>: - To start in remote auto, the selector switch located at the plant must be in the "remote auto" position, and the unit auxiliaries must be functioning normally. The Merwin operator can then send a start signal via the SCADA system, and the unit will roll, come up to speed, synchronize, and close the breaker automatically. The Merwin operator can then adjust the load as required or put the unit on load control. When the unit is on load control, the C&T Real Time Generation Control Desk computer controls the load directly.

Normal plant operation consists of receiving generation requirements on the load controller from the Portland Real Time Generation Control Desk via the SCADA system. The Swift units are then operated from HCC to meet Portland's request. The load controller, if selected to run the units, can change the plant output directly as required to meet the demand from Portland.

Swift Reservoir is the largest and uppermost impoundment on the Lewis River. There is no flow regulation above Swift Dam; therefore, reservoir elevations and project operations can be significantly affected by natural inflows. During the summer, PacifiCorp typically maintains reservoir levels within 5 feet of full pool to meet recreational needs. Reservoir elevations also are influenced by factors such as minimum streamflow releases below Merwin Dam, inflows, system load, and flood control.

When natural inflows to Swift Reservoir are in excess of power production capacity and reservoir storage space nears the prescribed minimum, spilling is initiated. During high run-off conditions, the projects operate under special guidelines established to manage peak storm runoff in accordance with the respective FERC licenses.

H.6.2 PROJECT OPERATION DURING FLOOD CONDITIONS

The current flood control operating procedures for the Lewis River Hydroelectric Projects are fully documented in PacifiCorp's Standard Operating Procedures for High Runoff (1994). The Swift No. 1 Project is remotely operated from the Merwin HCC but is routinely visited every day. The Merwin HCC is monitored 24 hours per day by an operator who has constant displays of reservoir and tailwater elevations for the 4 Lewis River Projects. In addition to the Company's monitoring equipment, the National Weather Service operates a network of automated precipitation gages and river gages that telemeter hydro-meteorological events on the Lewis River. The event data are received at the Cowlitz County Emergency Services office and simultaneously at the National Weather Service offices in Portland and Seattle. PacifiCorp also has real time access to this automated data.

During flood events when conditions require releases from Merwin Dam to be significantly greater than its turbine capacity, considerable coordination takes place between PacifiCorp, the National Weather Service, Clark County and Cowlitz County emergency services agencies, the City of Woodland, and, in very severe events, the U.S. Army Corps of Engineers. In general terms, PacifiCorp notifies the National Weather Service and county and local government of actual or expected large releases from Merwin Dam. The National Weather Service and the relevant county and local government agencies issue notifications and warnings to the public and, if the situation warrants, may initiate evacuations.

H.6.3 PROJECT SAFETY

In accordance with FERC guidelines issued February 22, 1988, PacifiCorp has prepared and maintains an Emergency Action Plan (EAP) for the Lewis River Hydroelectric Projects. The EAP details the procedures that PacifiCorp will take in the unlikely event of a dam failure (PacifiCorp 1999). The EAP is updated annually and new issues filed with the FERC every 5 years. The primary purpose of the EAP is to provide maximum early warning to people who may be affected by the sudden release of water caused by natural disaster, accident, or failure of any component of the Lewis River Hydroelectric Projects. Copies of the current EAP are kept at all times at the project and at appropriate company dispatch offices. Copies are also provided to county agencies that deal with emergency services in the project vicinity. The EAP clearly identifies whom PacifiCorp personnel must contact in the event of an emergency. The EAP describes the actions taken to provide public notification. PacifiCorp annually tests the EAP using a simulated emergency and provides training to responsible personnel.

In accordance with state law, PacifiCorp maintains personnel safety records. A review of these records from the most recent 5-year period (1998 through 2002) indicates there have been no lost time accidents and no deaths associated with project activities or operations.

PacifiCorp also maintains records of accidental injuries or deaths to members of the public associated with its hydro projects. A review of these records for the most recent 5-year period (1998 through 2002) indicates there have been no such reports. The current public safety plan was submitted to the FERC Portland Regional office on September 30, 1992. The plan was subsequently accepted on October 20, 1992.

To maintain a safe environment, project facilities are inspected on a regular basis. The powerhouse and dam are inspected daily. The spillway gates and motors are tested each year to pass high flows. The project is inspected by the FERC staff from the Portland Regional Office every 3 years. The most recent FERC Environmental and Public Use Inspection (EPUI) was conducted on April 1, 2002.

H.6.4 RECORD OF PROJECT HISTORY

The FERC license for the Swift Hydroelectric Project was issued October 29, 1956 for a 50 year duration. Construction was started in May 1956. The first unit went into commercial operation on September 5, 1958. A detailed description of the construction history is provided in a paper published by the American Society of Civil Engineers (ASCE) titled "Swift Dam Construction" by Harris H. Burke on June 24, 1958. It is included as Appendix A to Exhibit C.

The Swift Hydroelectric Project was designed by Bechtel Corporation. The dam was constructed by J.A. Jones Construction Company. The powerhouse was constructed by Guy F. Atkinson Company. Construction was completed in 1958.

Since 1956, when the initial license for the Swift Hydroelectric Project was granted by the FERC, no major additions or modifications have been made tot he project.

A list of project upgrades and improvements is included in Exhibit C of this license application.

H.6.5 PROJECT OUTAGES

PacifiCorp procedures for reporting forced outages at the Lewis River projects 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 H.6.5-1).

Prior to 2001, outage reporting was recorded in hand-written power logbooks, with different reporting procedures than are currently followed. Outages for this period are grouped by powerhouse unit, outage time, and total potential lost generation for the year (Table H.6.5-2). Actual outage occurrences are expected to have been fewer than shown due 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. Use of the nameplate rating likely overestimates the lost generation.

Table H.6.5-1. Swift No. 1 Project Outages (January 1, 2001 – May 21, 2003)

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Units	Total Unit Capacity (MW)	Cause	Potential Lost Generation (MWhrs)
Planned Outages 1/1/2001 through 5/21/2003						
01/05/2001 2:18:53 PM	01/15/2001 9:55:00 PM	247.60	Swift 13	80	Overhaul/Upgrade Outage	19,808.00
02/01/2001 10:34:50 AM	02/03/2001 3:35:00 PM	53.00	Swift 11, 12, 13	240	Annual Outage	12,720.00
02/07/2001 12:50:36 PM	02/10/2001 10:15:00 AM	69.40	Swift 12	80	Annual Outage	5,552.00
02/03/2001 3:35:00 PM	02/06/2001 4:00:00 PM	72.42	Swift 13	80	Annual Outage	5,793.30
02/10/2001 10:15:00 AM	02/11/2001 11:53:00 AM	25.63	Swift 11, 12, 13	240	Annual Outage	6,152.00
02/11/2001 11:55:00 AM	02/11/2001 10:50:00 PM	10.92	Swift 11, 12	160	Overhaul/Upgrade Outage	1,746.70
02/12/2001 7:29:25 AM	02/16/2001 11:30:00 AM	100.02	Swift 11	80	Maintenance Outage	8,001.30
02/20/2001 9:00:00 AM	02/20/2001 11:00:00 AM	2.00	Swift 12	80	Maintenance Outage	160.00
06/09/2001 9:00:00 AM	06/09/2001 3:00:00 PM	6.00	Swift 12	80	Non-Generation Issue	480.00
02/09/2002 8:18:00 AM	02/09/2002 4:18:00 PM	8.00	Swift 11, 12, 13	240	Maintenance Outage	1,920.00
02/16/2002 10:04:00 AM	02/16/2002 2:06:00 PM	4.03	Swift 11, 12, 13	240	Maintenance Outage	968.00
03/19/2002 10:00:00 AM	03/19/2002 3:23:00 PM	5.38	Swift 12, 13	160	Non-Generation Issue	861.30
03/21/2002 11:38:00 AM	03/21/2002 1:10:00 PM	1.53	Swift 12, 13	160	Non-Generation Issue	245.30
07/19/2002 10:20:00 AM	07/22/2002 8:34:00 AM	70.23	Swift 11, 12, 13	240	Non-Generation Issue	16,856.00
07/23/2002 7:28:00 AM	07/25/2002 12:40:00 PM	53.20	Swift 11	80	Maintenance Outage	4,256.00
09/16/2002 8:07:00 AM	10/04/2002 3:30:00 PM	439.38	Swift 11	80	Overhaul/Upgrade Outage	35,150.70
09/16/2002 8:07:00 AM	09/16/2002 9:44:00 AM	1.62	Swift 12, 13	160	Overhaul/Upgrade Outage	258.70
10/05/2002 8:00:00 AM	10/05/2002 10:00:00 AM	2.00	Swift 11	80	Maintenance Outage	160.00
08/08/2002 10:00:00 AM	08/08/2002 12:21:00 PM	2.35	Swift 11, 12, 13	240	Non-Generation Issue	564.00
08/13/2002 5:34:00 AM	08/13/2002 3:56:00 PM	10.37	Swift 11, 12, 13	240	Non-Generation Issue	2,488.00
08/14/2002 5:41:00 AM	08/14/2002 2:00:00 PM	8.32	Swift 11, 12, 13	240	Non-Generation Issue	1,996.00
08/15/2002 5:34:00 AM	08/15/2002 3:10:00 PM	9.60	Swift 11, 12, 13	240	Non-Generation Issue	2,304.00
08/23/2002 9:57:00 AM	08/23/2002 3:00:00 PM	5.05	Swift 11, 12, 13	240	Non-Generation Issue	1,212.00
08/27/2002 5:29:00 AM	08/27/2002 1:30:00 PM	8.02	Swift 11, 12, 13	240	Non-Generation Issue	1,924.00

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Units	Total Unit Capacity (MW)	Cause	Potential Lost Generation (MWhrs)
08/28/2002 5:31:00 AM	08/28/2002 2:20:00 PM	8.82	Swift 11, 12, 13	240	Non-Generation Issue	2,116.00
08/30/2002 5:40:00 AM	08/30/2002 1:57:00 PM	8.28	Swift 11, 12, 13	240	Non-Generation Issue	1,988.00
09/14/2002 5:43:00 AM	09/14/2002 6:35:00 PM	12.87	Swift 11, 12, 13	240	Non-Generation Issue	3,088.00
09/15/2002 5:32:00 AM	09/15/2002 3:32:00 PM	10.00	Swift 11, 12, 13	240	Non-Generation Issue	2,400.00
10/02/2002 8:35:00 AM	10/04/2002 3:30:00 PM	54.92	Swift 12	80	Overhaul/Upgrade Outage	4,393.30
10/28/2002 9:30:00 AM	10/31/2002 1:01:00 PM	75.52	Swift 12	80	Maintenance Outage	6,041.30
03/01/2003 8:50:00 AM	03/01/2003 2:10:00 PM	5.33	Swift 11, 12, 13	240	Maintenance Outage	1,280.00
Unplanned Outages 1/1/2001 through 5/21/2003						
01/16/2001 7:00:00 AM	01/16/2001 2:39:00 PM	7.65	Swift 12	80	Controls/Communication	612.00
02/08/2001 10:39:03 AM	02/08/2001 4:49:00 PM	6.17	Swift 13	80	Turbine	493.30
02/12/2001 10:10:00 AM	02/12/2001 12:35:00 PM	2.42	Swift 12	80	Turbine	193.30
03/30/2001 1:25:09 PM	03/30/2001 2:14:00 PM	0.82	Swift 11	80	Electrical Systems	65.30
04/24/2001 11:51:35 AM	04/27/2001 6:26:00 PM	78.57	Swift 11	80	Auxilary Systems	6,285.30
04/26/2001 7:11:51 AM	11/19/2001 6:35:00 PM	4,979.38	Swift 13	80	Electrical Systems	398,350.70
04/27/2001 6:36:05 AM	04/27/2001 7:25:00 AM	0.82	Swift 12	80	Controls/Communication	65.30
05/07/2001 3:07:11 PM	05/07/2001 5:50:00 PM	2.72	Swift 11	80	Generator/Exciter	217.30
05/08/2001 1:53:37 PM	05/08/2001 4:22:00 PM	2.47	Swift 11	80	Generator/Exciter	197.30
05/24/2001 5:35:17 AM	05/24/2001 6:46:00 AM	1.18	Swift 12	80	Controls/Communication	94.70
05/29/2001 5:23:03 AM	05/29/2001 6:36:00 AM	1.22	Swift 12	80	External Problems	97.30

Table H.6.5-1. Swift No. 1 Project Outages (January 1, 2001 – May 21, 2003) (continued).

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Units	Total Unit Capacity (MW)	Cause	Potential Lost Generation (MWhrs)
06/23/2001 6:42:00 PM	06/23/2001 7:29:00 PM	0.78	Swift 12	80	Controls/Communication	62.70
06/27/2001 7:20:00 AM	06/27/2001 8:06:00 AM	0.77	Swift 12	80	Controls/Communication	61.30
08/06/2001 9:18:00 AM	08/06/2001 9:33:00 AM	0.25	Swift 12	80	Controls/Communication	20.00

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Units	Total Unit Capacity (MW)	Cause	Potential Lost Generation (MWhrs)
08/07/2001 3:28:00 PM	08/07/2001 4:02:00 PM	0.57	Swift 12	80	Controls/Communication	45.30
12/24/2001 7:11:00 PM	12/24/2001 8:09:00 PM	0.97	Swift 12	80	Turbine	77.30
02/01/2002 3:01:00 PM	02/02/2002 5:25:00 AM	14.40	Swift 11, 12, 13	240	External Problems	4,464.00
04/21/2002 6:21:26 AM	04/27/2002 9:38:00 AM	147.28	Swift 11, 12, 13 Yale 2	240	External Problems	35,348.00
09/09/2002 7:10:00 AM	09/09/2002 7:54:00 AM	0.73	Swift 11	80	Controls/Communication	58.70
02/24/2003 1:50:00 AM	02/24/2003 2:53:00 AM	1.05	Swift 11	80	Generator/Exciter	84.00
04/11/2003 9:10:54 AM	04/11/2003 10:15:00 AM	1.07	Swift 13	80	Personnel Error	85.30

Table H.6.5-2. Swift No. 1 Project Outages (January 1, 1998 – December 31, 2000)

Year	Unit	Unit Capacity (MW)	Outage Hours			Potential Lost Generation (MWHrs.)
			Planned	Unplanned/ Forced	Total	
1998	Swift 11	68	724.78	43.68	768.46	52,255.28
	Swift 12	84.96	3,534.69	102.24	3,636.93	308,993.6
	Swift 13	68	4,689.31	58.14	4,747.45	322,826.6
1999	Swift 11	68	14.48	70.74	85.22	10,092.56
	Swift 12	84.96	677.50	1,252.71	1,930.21	163,990.6
	Swift 13	68	1,719.94	652.77	2,372.71	161,344.3
2000	Swift 11	68	*	*	*	*
	Swift 12	84.96	*	*	*	*
	Swift 13	68	*	*	*	*

* data unavailable

H.6.6 STATEMENT OF LICENSE COMPLIANCE

The original license for the Swift No. 1 Project was issued on October 29, 1956. A list of license articles that pertain to environmental resources is provided below.

Article 18 stipulates that discharges or operation shall be controlled by such reasonable rules and regulations as the Secretary of the Army may prescribe in the interest of navigation; the protection of life, health, and property; and for power production and other beneficial uses such as recreation.

Article 30 directs Licensee to cooperate with the Parks and Recreation Commission and the National Park Service to develop a Recreation Public Use Plan.

Article 31 states that the Licensee shall notify the Department of Anthropology, University of Washington, of the proposed construction of Swift Dam and reservoir so that the Department may negotiate with the Licensee for the purpose of undertaking archeological surveys and excavations, if considered desirable, prior to flooding of the reservoir area.

Article 32 directs the Licensee to make available funds up to $63,000 for expenses incurred by the Secretary of the Interior and the Departments of Fisheries and Game in carrying out such detailed studies as may be agreed upon by the Licensee, the Fish and Wildlife Service, and the Washington Departments of Fisheries and Game to devise means and measures for mitigating and replacing any losses to fish and wildlife that will result from project construction.

Since 1989, PacifiCorp has provided in excess of $63,000 toward joint studies to reduce project impacts on bull trout at Swift Reservoir. These funds have been used to purchase radiotags and gill nets in support of field studies, as well as providing for helicopter time. PacifiCorp has also provided labor to reduce costs incurred by the state and federal agencies. In 1994 and 1995, PacifiCorp contracted with the U.S. Forest Service (USFS) to conduct habitat surveys on known and suspected bull trout streams above Swift Dam. As a result of these studies, mitigation measures have been implemented, including changes in fishing regulations, decommissioning of roads by the USFS, increased enforcement presence, and the placement of bull trout information signs.

Article 33 states that "The Licensee shall construct, operate, and maintain or shall arrange for the construction, operation, and maintenance of such reasonable protective facilities including hatchery facilities, for the purpose of conserving fishery resources, and adequate facilities and measures for protecting wildlife and mitigating wildlife losses and comply with reasonable modifications of the project structures and operation in the interest of fish and wildlife resources as may be hereafter prescribed by the Commission upon the recommendation of the Departments of Fisheries and Game of the State of Washington and of the Secretary of the Interior after notice and opportunity for hearing."

Article 36 states that the Licensee shall develop a plan and enter into agreements with the USFS to: (1) alleviate damage to and ensure adequate protection and use of National Forest resources, and (2) relocate or replace facilities needed for National Forest administration insofar as they are affected by the proposed project. In 1993, PacifiCorp and the USFS cooperatively developed a Memorandum of Understanding (MOU) to manage Forest Service lands near Drift Creek to "establish the mechanism for coordinating resource management."

Articles 43 and 51 of the Merwin license pertain to operation of Swift No. 1. These articles are summarized in Section 7.6 of Exhibit H of the Merwin License Application Initial Information Package. A review of compliance records indicates the Swift No. 1 Project to be in compliance with its license articles.

H.8.0 LITERATURE CITED

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