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April 26, 2004

Ms. Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Via e-filing

Re: **California Energy Commission Staff Comments on PacifiCorp's Final License Application to the Federal Energy Regulatory Commission for the Klamath River Hydroelectric Project, FERC No. 2082**

The California Energy Commission Staff (Energy Commission Staff) is pleased to submit to the Federal Energy Regulatory Commission (FERC) the following comments on PacifiCorp's Final License Application (Application) to license its Klamath River Hydroelectric Project, FERC Project No. 2082 (Project).

The Energy Commission is California's lead energy information agency. Our attached comments are intended to bolster the evidentiary record by ensuring that the characterization and valuation of the project's hydroelectric generation are done properly, in accordance with the best energy data and analytic methods.

The Energy Commission Staff's primary recommendation to FERC - based on our understanding of the energy and biological resources associated with the Klamath Hydro Project - is that decommissioning may be a viable option given that the Project is a small energy facility with 161 MW total capacity and annual average production of 656 GWh. Consequently, decommissioning should be developed and fully evaluated as an alternative during federal review of PacifiCorp's application in accordance with the National Environmental Policy Act. We note that low power – high impact energy facilities can create substantial net environmental benefits if decommissioning proves to be feasible and cost-effective, and if replacement energy is available.

The Energy Commission Staff's principal technical comment concerns the market simulation methodology used to establish the Klamath Hydro Project's annual energy value of $70 per MWh and $48.5 million annually. Valuation of the Project's energy is one of the most important elements in the relicensing review process because all environmental mitigation cost estimates, and the ultimate balancing of project costs and benefits, are referenced to this valuation of project energy. Based on our review of FERC's regulations and appropriate methods for estimating current energy replacement costs, there is insufficient information to evaluate the energy value estimates provided in the Application. We cannot confirm that these figures are appropriate for use as the critically important valuation estimate for the Project's energy.

To determine the appropriate value for annual energy from the Project, we recommend that FERC provide additional clarification on the requisite methodology and calculations, and on the method used in the Application.

The Energy Commission looks forward to participating in the upcoming phases of FERC's relicensing process for the Klamath Hydroelectric Project. If you have any questions on the comments, please contact Jim McKinney of my staff at 916-654-3999 (jmckinne@energy.state.ca.us).

Please note that this comment package includes our technical comments and our 2003 report: *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*.

Sincerely,

ROBERT L. THERKELSEN
Executive Director

Attachments

CC: Mr. Toby Freeman,
Hydro Licensing Director, PacifiCorp

Mr. Michael Chrisman
Secretary, California Resources Agency

Mr. Ryan Broddrick
Director, California Department of Fish and Game

Ms. Celeste Cantu
Executive Director, California State Water Resources Control Board

PACIFICORP'S FINAL LICENSE APPLICATION
KLAMATH RIVER HYDROELECTRIC PROJECT
FERC NO. 2082

CALIFORNIA ENERGY COMMISSION STAFF COMMENTS TO THE FEDERAL ENERGY REGULATORY COMMISSION AND PACIFICORP

April 26, 2004

Part I – Introduction and California Energy Commission Authorities and Interests

Introduction

The California Energy Commission Staff (Energy Commission Staff) is pleased to submit to the Federal Energy Regulatory Commission (FERC) the following comments on PacifiCorp's Final License Application (Application) to relicense its Klamath River Hydroelectric Project, FERC Project No. 2082 (Project).

The Energy Commission Staff's comments are intended to bolster the evidentiary record of the proceeding by ensuring that the characterization and valuation of the project's hydroelectric generation are done properly, in accordance with the best available energy data and analytic methods.

This is the first time the Energy Commission Staff has offered comments to FERC on the energy and environmental issues associated with an application to relicense a hydroelectric facility. The Klamath River is one of the two most important remaining salmon rivers in California, providing significant habitat through most of its length for endangered runs of Chinook and coho salmon and steelhead trout. The Klamath's salmonid fisheries are regionally significant in biological, economic, tribal, social and cultural terms. Fully 300 miles of mainstem and tributary salmonid habitat could be made accessible to Klamath River salmonids if the barriers to passage created by PacifiCorp's lower project dams, beginning with the Iron Gate Dam at river mile 190, were removed.

The Energy Commission Staff's primary recommendation to FERC – based on our understanding of the energy and biological resources associated with the Klamath River Hydro Project – is that partial and full decommissioning alternatives should be developed and fully evaluated during federal review of PacifiCorp's Application in accordance with the National Environmental Policy Act.

The Energy Commission Staff's principal technical comment concerns the market simulation methodology used to establish the Klamath Hydro Project's annual energy value of $70 per MWh and $48.5 million annually. Valuation of the project's energy is one of the most important elements in the relicensing review process because all environmental mitigation cost estimates, and the ultimate balancing of project costs and benefits, are referenced to this valuation of project energy.

Based on our review and understanding of FERC's regulations, and appropriate methods for estimating current energy replacement costs as articulated in the 1995 Mead Paper Decision, there is insufficient information to evaluate the energy value estimates provided in the Application. We cannot confirm that these figures are appropriate for use as the critically important valuation estimate for the project's energy.

The Energy Commission Staff has provided four different forecasts and estimates of wholesale and avoided energy costs that may help inform the record on the Project's appropriate energy value.

California Energy Commission Authorities

The California Energy Commission is California's lead energy information agency. Under the Warren-Alquist Act, the Energy Commission is charged with the collection, analysis, and dissemination of detailed information concerning "all forms of energy supply, demand, conservation, public safety, research, and related subjects."[1] In this regard, the Energy Commission employs a full-time staff with expertise in relevant matters such as analysis of electricity power supply, demand, price and related issues.

The Energy Commission has exclusive jurisdiction for certifying all thermal power plant sites and related facilities in California with installed capacity of 50 megawatts (MW) or more. The Energy Commission's power plant siting program is fully certified under the California Environmental Quality Act (CEQA) by the California Resources Agency.[2] Accordingly, the Energy Commission employs a full-time staff with expertise in a wide range of environmental and energy issues pertaining to large power plants and related facilities throughout the State of California. In carrying out its mandates, the Energy Commission is responsible for balancing the need for a reliable electricity supply system with the equally important need to protect environmental quality.[3]

The Energy Commission's legal authorities and responsibilities were expanded and bolstered in the fall of 2002 when the California Legislature passed the Integrated Energy Policy Act (Senate Bill 1389). This Act directs the Energy Commission to prepare a biennial ***Integrated Energy Policy Report*** (Energy Report) for submission to the Governor and Legislature. The Act also states that

[1] California Public Resources Code (PRC) Sections 25216.5(d) and 25309.3(c).

[2] PRC Section 25500 *et seq.,* and Title 14, CCR, Section 15251(k).

[3] PRC Section 25001.

information contained in the Energy Report will form "the foundation of energy policies and decisions affecting the state."[4]

One of the findings in the first ***Energy Report,*** issued in December 2003***,*** concerns hydroelectricity:

> "Hydroelectricity has historically played an important role in meeting California's electricity needs. Its low production costs and unique ability to meet critical peak demand have long benefited the state's ratepayers. Some hydroelectric projects unfortunately have serious environmental consequences such as significant, ongoing impacts to many California rivers and streams, native salmon and trout populations, and the water quality needed to support sustainable riverine ecosystems. … Since the FERC licensed most of the state's hydroelectric facilities more than 30 years ago, these facilities were not subject to current environmental standards. By 2015, 44 FERC-licensed projects in California will seek renewals, affording the state the rare opportunity to address problems with existing fisheries and aquatic resources. ***In addition, decommissioning of high environmental impact hydroelectric facilities that supply little power is a possible method of restoring important aquatic habitat***"[5] (emphasis added).

Part II – Summary of the 2003 California Energy Commission Staff Klamath Energy Assessment

At the request of the California Resources Agency – California's cabinet level agency responsible for fish, wildlife, water, energy, recreation and natural resources, and the California State Water Resources Control Board – California's lead state water quality regulatory agency for Clean Water Act and water rights issues, Energy Commission Staff conducted a ***Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project***[6] (Energy Assessment) in May 2003. The Energy Commission Staff submits the Energy Assessment into the Klamath relicensing docket as an attachment to this comment. Following is a summary of key findings from the Energy Assessment.

- From the perspective of potential impacts to electric resource adequacy, the Energy Commission Staff believes that potential decommissioning of some or all of the Klamath Project is a viable project alternative that should be evaluated by FERC during the relicensing process. Energy facilities with low power values and high levels of environmental impact

[4] PRC Section 253000

[5] *2003 Integrated Energy Policy Report*, California Energy Commission, Docket No. 02-IEP-1, Publication No. 100-03-019, December 2003.

[6] *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, California Energy Commission Staff Report, Publication No. 700-03-007, May 2003.

can create important restoration benefits if decommissioning proves to be cost-effective, feasible, and if alternative power resources are available. The Klamath project is a small energy facility with 161 MW total capacity and annual average production of 656 GWh. Loss of some or all of this energy would not significantly affect PacifiCorp's ability to provide electricity to its 1.6 million customers.

- PacifiCorp is currently a net importer of energy, and secures 38% of its electricity through power purchase agreements. PacifiCorp may face a 4,100 MW shortfall by 2014 if no additional generation is secured, or if their existing long-term power purchase agreements are not renewed. The scale of the Klamath Project is small compared to the scale of additional generation, transmission or reduced demand growth needed to meet load, reserve margins and transmission system reliability. Consequently, it is likely that decommissioning would not have a significant reliability impact on a regional scale.

- Replacement energy is available locally and regionally. A 484 MW natural gas cogeneration plant and a 93 MW combustion turbine peaker project were recently built in Klamath County, Oregon. In addition, two new combined cycle projects in Klamath County totaling about 1,600 MW are undergoing licensing review by the Oregon Department of Energy. The 543 MW Klamath Energy Project is expected to be licensed by the end of 2004, while the 1,150 MW COB Energy Facility Project is now in the evidentiary phase of its licensing review.[7] Replacement energy would likely cost more than the energy from the Klamath Hydroelectric Project.

- The Energy Commission's Energy Assessment is a preliminary study. For potential decommissioning, additional study is needed to assess local reliability issues, to determine the overall benefits, costs and risks to stakeholders and the environment, and define an appropriate decommissioning strategy.

- Klamath River is one of the most important salmon rivers in California, and salmon restoration is an important state policy objective.

- Energy generation is one of several contributing factors to the decline of Klamath River fisheries. The Iron Gate and Copco Dams completely block salmonids from accessing approximately 300 miles of mainstem and tributary habitats. Water quality problems associated with the Bureau of Reclamation's Klamath Irrigation Project also contribute to salmon fisheries decline. The Energy Commission recognizes that water quality must be substantially improved as part of government efforts to restore the Klamath salmonid fisheries.

[7] *Energy Facility Siting Council Announcements and Notices Page*, Oregon Department of Energy Website, http://www.energy.state.or.us/siting/announce.htm, consulted April 19, 2004.

Part III – Energy Commission Staff Technical Comments on Parts D and H of PacifiCorp's Klamath Final License Application

The Energy Commission Staff's technical comments and clarifying questions focus on three main issues: 1) clarifying and confirming Klamath hydroelectric peaking operations; 2) examining PacifiCorp's market valuation method and results in establishing the Project's energy value; and 3) reviewing the "capital cost of alternative generation" method to establish the Project's energy value. Valuation of the project's energy is one of the most important elements in the relicensing review process because all environmental mitigation cost estimates, alternatives, and the ultimate balancing of project costs and benefits, are referenced to this valuation of project energy.

A. Clarify and Confirm Hydroelectric Operations and Peaking Power Generation at Klamath

Sections D5 and H1.3
In Section D5, PacifiCorp describes Klamath operations as 64% peaking production (447,209 MWh) and 36% baseload production (249,834 MWh) in an average year (Ex D at 5-1). In Section H1.3, PacifiCorp describes the Klamath Project as being subservient to the Bureau of Reclamation's (Bureau) irrigation project and to Endangered Species Act (ESA) fish flows: "The Klamath Irrigation Project significantly controls the amount of water released into the hydroelectric project. … 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) total in three reservoirs. As such, powerhouse operations are dependent on Klamath River flows needed to address ESA requirements."

"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." (Ex H at 1-3)

Discussion and Comment
Establishing the quantity and time of production for peaking energy is an important first step in establishing the project's energy value. While the Klamath Project clearly provides peaking generation, clarification is needed to understand how much peaking power is generated - and at what time of the day, month and year this occurs. Water diversions for the Bureau's irrigation project and fish

flows appear to significantly limit the dispatch flexibility of the Klamath Project's generation. Definitions of peak load and peak energy are important because they correlate with varying levels of market prices.

In California, power made available during super peak periods will be valued quite a bit higher than shoulder peak or non-peak power. Hydropower projects in California that supply peaking power generally have large amounts of reservoir storage and can control dispatch of generation to meet peak load demands on summer weekday afternoons.

Definitions and distinctions of Peak and Off-Peak are not clearly presented in the Application. Peak Hours for PacifiCorp are different than for the California Independent System Operator (CAISO). As noted in the Energy Assessment, "Peak loads for the PacifiCorp's West control area can occur in summer or winter." PacifiCorp's 2002 winter peak totaled 7,585 MW, while the summer peak totaled 8,511 MW (Ex H at 3-1). Each day has its own peak periods of demand. Unlike CAISO, the highest peak periods are normally the morning hours shortly after dawn, especially during the winter heating season. In Section H2.1.1, PacifiCorp defines peaking resources as "generation that can quickly meet energy needs during highest-use periods, typically during periods of extreme heat or cold" (Ex H at 2-3). This corresponds with general definitions of peak load energy. However, in a filing before the Oregon Public Utilities Commission, PacifiCorp states that "Peak hours are defined as 6:00 a.m. to 10:00 p.m., Monday through Saturday" with peak hours accounting for 57% of load, while 43% are off peak."[8] This broad, non-differentiated definition of peak load is not appropriate for valuing the energy produced by the Project.

The Energy Commission Staff seeks a more precise definition of peak load and peaking generation. Other distinctions are also used within the utility industry, such as Super Peak, and Shoulder (or Load Following), at a minimum. For example, Pacific Gas and Electric Company in California forecasts capacity and energy for its hydro resources using nine temporal categories related to demand. Four are during weekdays: Superpeak, Shoulder1, Shoulder2, and Offpeak. Another four periods are during weekends: Superpeak, Shoulder1, Shoulder2, and Offpeak. The ninth temporal category is called "Flat", for constant output, 24 hours x 7 days. The all-embracing Flat period is equivalent to a baseload plant running continuously. For hydro plants, Flat energy is based on minimum input flows to a "run-of-river" plant, or minimum and continuous water releases to channels downstream from a powerhouse.

[8] PacifiCorp's Avoided Cost Filing Before the Oregon Public Utilities Commission, *Avoided Cost Information and Proposed Tariff Sheet for Projects one MW and Smaller*, Nov 10 2003, page 1, and Attachment B, page 2.

Questions and Information Requests

- How does PacifiCorp define "peak hours" and "peaking energy"? Do these definitions change on a monthly or seasonal basis? Does the company use other distinctions in contracting and scheduling resources, such as Super-Peak and Shoulder (Load Following) periods? Does the company distinguish elsewhere between Weekdays and Weekends? How does the usage of "peak hours" in this license application equate or differ from industry conventions such as daily price reporting of "Peak" and "Off-Peak" energy trading in the *Energy Market Report* (published by Portland-based Economic Insight, Inc.)?

- Is there a more disaggregated or specific definition of "peak load" that PacifiCorp uses to characterize Klamath Project power in its financial models?

- Please provide an average annual load duration curve for PacifiCorp's west-side control area so that the distribution of peak and non-peak load can be better understood.

- Please provide temporal summaries of the Klamath project's generation on a historic daily, monthly and average annual basis.

- What is the average energy generation (in MWh per year) from PacifiCorp's resources located in California? How much energy did PacifiCorp distribute to its retail customers in California in 2001, 2002, and (if available) 2003?

- Given the very limited water storage capacity within the project area, and given that the USBR controls water releases from Upper Klamath Lake, how important is the project (if at all) in meeting the summer and winter annual peak load demands? How important (measurably) is the flexible dispatch of capacity from the project for meeting daily load peaks in the control area?

- In terms of reliability and economic value, how does PacifiCorp assess the nameplate and dependable capacity values of project resources? To what extent are these values derated by year-to-year and long-term uncertainties related to available runoff into Upper Klamath Lake?

- Specifically, what monetary value does PacifiCorp place on dependable capacity used to meet daily load peaks (such as JC Boyle, Copco 1, and Copco 2), and how does this compare to the monetary value of dependable capacity at Iron Gate PH?

- To model and simulate Peak versus Off-Peak energy production, please provide hourly generation for each plant in Excel (or equivalent) going back to 1996.

- In terms of reliability and economic value, how does PacifiCorp assess other project-specific generation attributes such as flexible dispatch, and availability of ancillary services? Specifically, what would be the levelized annual value of spinning reserves, non-spinning reserves, and replacement reserves provided by Copco 1, Copco 2, and Iron Gate?

- If the Klamath hydro project were not available to PacifiCorp, what other supply resources would be available starting in 2006 to meet daily load peaks?

B. Clarify and Confirm PacifiCorp's Market Price Valuation of Klamath Energy

FERC regulations state that applicants shall provide: "The on-peak and off-peak values of the project power, and the basis for estimating the values."[9] According to FERC, project power values can be assessed using either 1) the cost of replacement power from the most likely thermal alternative, or 2) simulated market prices.[10] FERC's Mead Paper decision further specifies that only current energy replacement costs should be used in order to avoid controversies about cost escalation or discounting.[11] This emphasis on current energy replacement costs is also known as the "current cost method." As FERC stated in its 2003 Draft EIS on the Davis Dam in Alaska:

> "As articulated in Mead Corporation, Publishing Paper Division (72 FERC 61,027), the Commission's approach to evaluating the overall economics of a hydroelectric project uses current costs to compare the costs of the project and likely alternative power. We consider the power benefit of the project to be equal to the current cost of the alternative source of power that would be used in the absence of the project. We use a 30-year period of analysis with <u>no forecasts of potential future inflation, escalation, or deflation to convert all costs to a levelized annual value</u>. The levelized annual value is a convenient metric for comparing a cost to a resulting benefit, whether the benefit is measured in dollar-value or non-dollar-value terms."[12] (Emphasis added.)

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[9] C.F.R. Section 4.51 (e) (8)
[10] Workshop on Evaluating the Economics of Hydroelectric Projects at FERC, Office of Hydropower Licensing, February 3, 1998.
[11] FERC Order Issuing New License, FERC Project No. 2506, Mead Paper Corporation, July 13, 1995.
[12] Draft Environmental Impact Statement for the Glacier Bay National Park and Preserve: Falls Creek Hydroelectric Project and Land Exchange (P-11659), October 2003.

Section D5 – Estimated Annual Value of Power
PacifiCorp describes its methodology and conclusions in estimating the value of the Klamath Project energy using a market simulation approach. "The market value of energy is based on incremental power cost estimates 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" (Ex D at 5-1).

For the 30-year license period beginning in April 2006, PacifiCorp estimates the annual average power value to be $70/MWh, apparently using nominal dollars. The range of values for this energy varies from $56 (low) to $83 (high), averaging California-Oregon Border and Mid-Columbia values. Average on-peak power is valued at $74 / MWh, while non-peak power is valued at $62 / MWh. These PacifiCorp figures are summarized in the following table.

PacifiCorp's Total 30-yr Average Annual Production
For the Proposed Klamath Project

	MWh	Ratio (%)	Value ($/MWh)	Total Value ($mil)
Peak	447,209	64	74	32.9
Off-Peak	249,834	36	62	15.6
Total	697,043			48.5

Discussion and Comment
Based on the information provided, it is difficult to interpret how the 30-year average total value of $70 / MWh was derived, and what it is intended to represent. PacifiCorp's Application does not provide sufficient information to evaluate whether the calculation and final 30-year average value conforms with FERC regulations and guidance for estimating project energy values using a market simulation approach. More importantly, the 30-year average value does not appear to conform with FERC's 1995 Mead Paper decision order that only current energy replacement costs should be used in establishing a project's energy value. Based on the information contained in the Application, the Energy Commission is further concerned that PacifiCorp's method for calculating the 30-year average energy value may not conform with current practices for using market information and forecast models to estimate wholesale energy costs. Based on the information provided, the Energy Commission cannot yet comment on whether the $70 / MWh is high or low or within a reasonable range of estimates. Based on our review and understanding of FERC's regulations and appropriate methods, and the information provided at this time, we cannot confirm that these figures are appropriate for use as the critically important valuation estimate for the project's energy.

Questions

- Please provide a description of the “internal market clearing price model” used to derive the value estimates of replacement energy.

- Please provide the input assumptions to the market clearing price model and simulation results that were used to derive the 30-year average energy values.

- Please clarify and confirm that the forecast energy values are in nominal dollars, and are not real dollars referenced to a particular date.

- To what extent does the application rely upon, diverge from, or extrapolate from the energy price forecasts and natural gas price forecasts in the May 2003 Integrated Resource Plan (Table C.26, page 226)? These IRP estimates of energy prices also appear to be in nominal dollars, including a 2.5% inflation rate as a key input assumption. Also, the IRP market prices are only forecast through March 31, 2032, four years short of the prospective license period through 2036.

- Does PacifiCorp expect its retail customer load in California to grow at 2.12% annually, as indicated in the IRP for the general area?

- For comparison to wholesale energy price forecasts by other entities, please provide the deflator series used to convert these forecast prices into a levelized cost for three appropriate years: 2000, 2002, and 2004. Using a deflator series, please calculate supplemental and replacement costs in real dollars (e.g., year 2004 dollars).

- The IRP price forecasts are for 7X24 “Flat” energy prices, with a single average price given for an entire year. How did PacifiCorp apply this price forecast to the expected average Peak and Off-Peak energy delivered by project resources? If a supplemental or different model run for energy prices was performed, please provide that data and the associated input assumptions.

- What monetary value does PacifiCorp place on ancillary services, by resource, from the Project? Are any of these project resources considered essential in the California local area, such as for black start capability or voltage regulation?

- The generating resources in California at Fall Creek, Copco 1, Copco 2, and Iron Gate are all certified eligible renewable resources. How essential are these resources to PacifiCorp for meeting the company’s Annual Procurement Targets set by the state’s Renewable Portfolio Standard (RPS)? If these four generating resources were not available to

PacifiCorp, how would PacifiCorp be able to meet its RPS obligations through 2017?

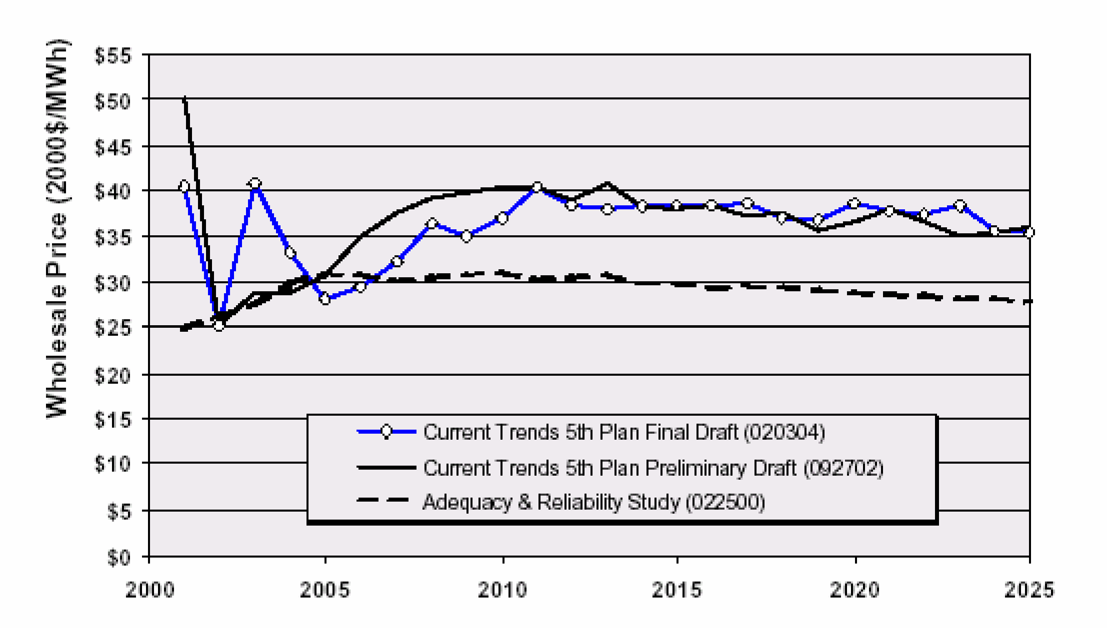
Comparison to Other Estimates of Current and Forecast Wholesale Costs
The Energy Commission Staff presents other current and forecasted wholesale electricity costs estimates to illustrate the range of estimates that are presently available. It is important to note that each forecast uses assumptions that are specific to the purposes and needs of the organization preparing the forecast. Readers should not be mislead into reading this summary as an "apples to apples" comparison with PacifiCorp's 30-year average figure of $70 / MWh.

1. **Northwest Power and Conservation Council 5th Draft Power Plan Wholesale Power Price Forecast**
   The Northwest Power and Conservation Council released the 5th draft of its Power Plan and Wholesale Price Forecast in March 2004. "The forecast levelized cost of power at the mid-Columbia trading hub for the period 2004 through 2025 is $36.50 per megawatt- hour (year 2000 dollars1) (Figure 1). In Figure 1, the current forecast is compared to two earlier forecasts - the preliminary draft forecast released in September 2002 (levelized value of $38.00/MWh) and the forecast prepared in conjunction with the Council's Adequacy and Reliability Study of February 2000 (levelized value of $29.90/MWh).

   The initial years of the forecast conform to historical price behavior. Prices are shown declining from 2000-01 highs, then rising in 2002 as a result of gas price increases. Forecast prices decline from 2003 highs as gas prices ease, then rise through 2010 as loads recover and the current capacity surplus is exhausted. Average prices are forecast to be stable through the remainder of the planning period as slowly increasing natural gas prices are offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Not forecast beyond 2003 are likely episodes of price excursions resulting from volatility in the gas market or poor hydro conditions."[13] (Pages 1 to 3).

[13] *Northwest Power and Conservation Counsel 5th Draft Power Plan Wholesale Power Price Forecast*, March 2004. Available at http://www.nwppc.org/news/2004_02/4.pdf.

Figure 1: Current and recent forecasts of average annual wholesale power price at the Mid-Columbia trading hub



2. **PacifiCorp's Avoided Cost Filing at Oregon PUC**
   In November 2003, PacifiCorp filed an updated avoided cost estimate at the Oregon Public Utilities Commission. "These avoided costs are estimated using the Company's existing methodology which bases avoided costs on the marginal production costs of existing units (2003-2006) and the cost of a gas-fired combined cycle combustion turbine (2007 and thereafter). … Attachment A, Exhibit 1 shows avoided costs that have been stated … for peak and off-peak periods. … Attachment A, Exhibit 2 shows avoided capital costs. … This exhibit also shows total avoided costs at various assumed capacity factors."[14]

[14] *Revised Avoided Cost Filing Before the Oregon Public Utilities Commission*, Advice No. 03-016, Schedule 5, PacifiCorp, November 10, 2003.

From Attachment A, Exhibits 1 and 2:

Exhibit 1
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs ($/kW-yr)	Total Avoided Energy Cost ($/MWH)	Capacity Cost Allocated to On-Peak Hours ($/MWH)	On-Peak 4,993 Hours ($/MWH)	Off-Peak 3,767 Hours ($/MWH)
	(a)	(b)	(c)	(d)	(e)
			(a) /(8.76 x 85% x 57%)	(b) + (c)	(b)
Avoided Resource					
2003	$0.00	$23.40 (1)	$0.00	$23.40	$23.40
2004	$17.60	$24.60	$4.15	**$28.74**	**$24.60**
2005	$18.04	$28.74	$4.25	$32.99	$28.74
2006	$18.49	$28.31	$4.36	$32.67	$28.31
Combined Cycle					
2007	$75.81	$33.10	$17.86	$50.96	$33.10
2008	$77.71	$33.79	$18.31	$52.10	$33.79
2009	$79.65	$33.27	$18.77	$52.04	$33.27
2010	$81.64	$31.05	$19.24	$50.28	$31.05
2011	$83.69	$30.06	$19.72	$49.78	$30.06
2012	$85.78	$31.00	$20.21	$51.21	$31.00
2013	$87.92	$31.94	$20.72	$52.66	$31.94
2014	$90.12	$29.01	$21.23	$50.25	$29.01
2015	$92.37	$29.66	$21.76	$51.43	$29.66
2016	$94.68	$31.53	$22.31	$53.84	$31.53
2017	$97.05	$33.26	$22.87	$56.12	$33.26
2018	$99.48	$34.17	$23.44	$57.61	$34.17
2019	$101.96	$35.16	$24.02	$59.19	$35.16
2020	$104.51	$36.21	$24.62	$60.83	$36.21
2021	$107.12	$36.31	$25.24	$61.55	$36.31
2022	$109.80	$37.29	$25.87	$63.16	$37.29
2023	$112.55	$38.31	$26.52	$64.83	$38.31
2024	$115.36	$39.37	$27.18	$66.55	$39.37
2025	$118.25	$40.54	$27.86	$68.40	$40.54
2026	$121.20	$41.71	$28.56	$70.27	$41.71
2027	$124.23	$42.89	$29.27	$72.16	$42.89

Exhibit 2
Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor		
			75%	85%	95%
	($/kW-yr)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
			(b)+((a)/8.76 x 0.75)	(b)+((a)/8.76 x 0.85)	(b)+((a)/8.76 x 0.95)
Avoided Resource					
2003	$0.00	$23.40 (1)	$23.40	$23.40	$23.40
2004	$17.60	$24.60	$27.28	$26.96	$26.71
2005	$18.04	$28.74	$31.48	$31.16	$30.90
2006	$18.49	$28.31	$31.12	$30.79	$30.53
Combined Cycle					
2007	$75.81	$33.10	$44.64	$43.28	$42.21
2008	$77.71	$33.79	$45.62	$44.23	$43.13
2009	$79.65	$33.27	$45.39	$43.97	$42.84
2010	$81.64	$31.05	$43.47	$42.01	$40.86
2011	$83.69	$30.06	$42.80	$41.30	$40.12
2012	$85.78	$31.00	$44.05	$42.52	$41.30
2013	$87.92	$31.94	$45.32	$43.75	$42.51
2014	$90.12	$29.01	$42.73	$41.12	$39.84
2015	$92.37	$29.66	$43.72	$42.07	$40.76
2016	$94.68	$31.53	$45.94	$44.25	$42.91
2017	$97.05	$33.26	$48.03	$46.29	$44.92
2018	$99.48	$34.17	$49.31	$47.53	$46.12
2019	$101.96	$35.16	$50.68	$48.86	$47.41
2020	$104.51	$36.21	$52.12	$50.25	$48.77
2021	$107.12	$36.31	$52.62	$50.70	$49.18
2022	$109.80	$37.29	$54.00	$52.03	$50.48
2023	$112.55	$38.31	$55.44	$53.43	$51.84
2024	$115.36	$39.37	$56.93	$54.86	$53.23
2025	$118.25	$40.54	$58.54	$56.42	$54.75
2026	$121.20	$41.71	$60.16	$57.99	$56.27
2027	$124.23	$42.89	$61.79	$59.57	$57.81

Comment
Note that 2004 peak energy (Exhibit 1) is valued at $28.74 / MWh, and that the $70 / MWh figure (in presumed nominal dollars) is not reached until 2026. Total 2004 avoided costs (Exhibit 2) at several capacity factors are in the $26 and $27 / MWh range.

3. **PacifiCorp's Integrated Resource Plan's Wholesale Price Forecast**
PacifiCorp's Integrated Resource Plan contains forecast information that appears to serve as the basis for their Klamath hydropower valuation and

their avoided cost filing. The explanation and forecast are presented below.

From Appendix C Assumptions:
“Prices are modeled from 2002 through 2031 on a fiscal year basis for Mid Columbia, COB, and Palo Verde. The curves is (sic) a blend derived from near-term forward prices from the market and long-term fundamental price scenarios simulated in the MIDAS model. Market prices as of August 01, 2002 were used for blending. The MIDAS cases were run on August 1, 2002. The deterministic analysis uses the medium – Cyclical Growth case, 08-01-02 market prices blended with the MIDAS Cyclical Growth (CG16).

Similarly, the natural gas market prices used are for a medium case. The blending of forward market prices and fundamental model prices uses the following methodology:
- Forward market prices are solely used through May 2005.
- June through November 2005 is weighted 75% forward market 25% MIDAS.
- December 2005 through May 2006 is a 50-50 weight between market and MIDAS.
- June through November 2006 is weighted 25% market 75% MIDAS.
- Beginning December 2006 only MIDAS results are used.”

For the period 2002 - 2031

Table C.26 Wholesale Market Prices

Flat Prices (7X24) Fiscal Year Period		Medium Price Forecast COB	PV	MdC
Apr-03	Mar-04	$ 32.10	$ 30.84	$ 30.12
Apr-04	Mar-05	$ 32.91	$ 32.29	$ 31.03
Apr-05	Mar-06	$ 35.16	$ 32.68	$ 33.35
Apr-06	Mar-07	$ 39.34	$ 33.54	$ 38.94
Apr-07	Mar-08	$ 44.50	$ 37.34	$ 44.99
Apr-08	Mar-09	$ 49.50	$ 43.15	$ 49.88
Apr-09	Mar-10	$ 42.23	$ 38.66	$ 42.53
Apr-10	Mar-11	$ 44.92	$ 41.58	$ 44.90
Apr-11	Mar-12	$ 50.94	$ 47.69	$ 50.91
Apr-12	Mar-13	$ 54.12	$ 50.66	$ 53.42
Apr-13	Mar-14	$ 48.50	$ 46.54	$ 48.06
Apr-14	Mar-15	$ 53.57	$ 51.71	$ 53.12
Apr-15	Mar-16	$ 57.62	$ 55.22	$ 57.10
Apr-16	Mar-17	$ 58.26	$ 56.42	$ 57.89
Apr-17	Mar-18	$ 58.76	$ 58.39	$ 57.77
Apr-18	Mar-19	$ 60.42	$ 60.57	$ 59.74
Apr-19	Mar-20	$ 60.94	$ 61.48	$ 60.19
Apr-20	Mar-21	$ 60.82	$ 62.61	$ 60.25
Apr-21	Mar-22	$ 62.40	$ 63.19	$ 61.72
Apr-22	Mar-23	$ 63.96	$ 64.77	$ 63.26
Apr-23	Mar-24	$ 65.56	$ 66.39	$ 64.84
Apr-24	Mar-25	$ 67.20	$ 68.05	$ 66.46
Apr-25	Mar-26	$ 68.88	$ 69.75	$ 68.12
Apr-26	Mar-27	$ 70.60	$ 71.49	$ 69.83
Apr-27	Mar-28	$ 72.37	$ 73.28	$ 71.57
Apr-28	Mar-29	$ 74.18	$ 75.11	$ 73.36
Apr-29	Mar-30	$ 76.03	$ 76.99	$ 75.20
Apr-30	Mar-31	$ 77.93	$ 78.91	$ 77.08
Apr-31	Mar-32	$ 79.88	$ 80.88	$ 79.00

Comment

2004 estimated wholesale costs (line 3) are in the $32 to $35 / MWh range across the three futures trading hubs. Note that these are nominal dollars for flat, or non-peak, energy.

4. California Energy Commission Consultant Report on California Hydro Facility Avoided Costs

As part of the Energy Commission's 2003 investigation into hydropower energy and environment issues, the M.Cubed consulting firm was retained to estimate project-specific avoided costs for California hydro facilities undergoing FERC relicensing.

"Table 1 shows for each FERC Project, the average revenues per megawatt-hour (MWH) generated. Whether a project has pondage to store and regulate flow releases, and whether it has automatic generation control (AGC) to facilitate provision of system regulation and spinning reserves significantly influences resulting revenues. For run of river facilities, that do not have significant storage and do not vary output except for changes in river flows so that these do not sell ancillary services, the average annual revenues were $30 to $35 per MWH or $150 to $180 per kilowatt-year (KW-Year). For projects that can provide ancillary services, these sales can add $10 to $35 per MWH or $30 to $200 per KW-Year. For example, the Spring Gap-Stansilaus Project, which has AGC and a small flow relative to turbine capacity, collects 64% of its revenues through ancillary service sales."[15]

Table 1
Comparison of Hydro Plant O&M Costs and Avoided Costs

FERC #	Project Name	Owner	Capacity MW	O&M $/MWH	Avoided Costs* $/MWH
2687	Pit No 1	PG&E	60.0	$4.49	$30.61
		PG&E	317.0	$2.29	$29.39
		PG&E	340.5	$2.55	$72.39
		PG&E	4.4	$13.01	$30.39
		PG&E	26.7	$12.73	$31.58
		PG&E	20.0	$5.35	$27.31
1962	Rock Creek – Cresta	PG&E	180.0	$4.43	$35.42
		PG&E	342.6	$4.05	$52.01
		PG&E	142.8	$2.51	$44.00
		PG&E	7.0	$14.71	$34.02
137	Mokelumne	PG&E	217.2	$7.57	$43.19
		PG&E	87.9	$5.52	$80.92
		PG&E	11.5	$10.02	$34.32
			150.2	$6.82	*$45.11*
			373.3	$5.08	*$45.11*
			165.7	$4.47	*$45.11*
			98.8	$3.71	*$45.11*
			180.9	$3.89	*$45.11*
			10.8	$5.32	*$45.11*
			0.0	NA	NA
			2.5	$27.40	$30.17
			12.0	$13.37	$34.20
			2.3	NA	NA
			1.2	$146.99	NA
	Feather River/Oroville	CDWR	762.9	NA	$45.39
2101	Upper American River	SMUD	641.0	NA	NA

* The revenues and generation from all of the units identified in the ISO database for a particular FERC Project were aggregated. The ISO does not distinguish the output from individual units in the SCE Big Creek Project, so the values shown are the average across the entire set of projects.

[15] *Hydropower Economics and Licensing Effect on Costs and Power Production*, California Energy Commission Consultant Report, M.Cubed and Kessler and Associates in association with Aspen Environmental, Report No. 100-04-002, March 2004.

Summary Comment
The Energy Commission Staff presents these four different market estimates of wholesale electric costs and project-specific avoided costs in order to provide a comparative range of current replacement energy costs for the Klamath Hydroelectric Project. The Northwest Power and Conservation Council estimates long-term levelized costs of power at the mid-Columbia trading hub at $36.50 / MWh in year 2000 dollars. PacifiCorp's Oregon PUC Avoided Cost Filing shows 2004 peak energy prices at $28.74 and off-peak prices at $24.60 / MWh. The same filing estimates total avoided costs for 2004 to range between $26.71 and $27.28 / MWh. PacifiCorp's Integrated Resource Plan (Table C26) estimates 2004 flat energy prices at the mid-Columbia hub to be $33.35, while California-Oregon Border hub prices are estimated at $35.16.

The Energy Commission's consultant report estimating avoided costs for 26 California hydroelectric projects of widely varying capacity, peaking capability, pondage and provision of ancillary services shows a range of avoided costs from $27 to $45 / MWh for 23 projects.

The Energy Commission Staff's 2003 Klamath Energy Assessment assumed $50 / MWh for replacement energy, which totaled $32.8 million for 656.2 GWh.

C. Cost and Availability of Alternative Power Resources

Sections D6 and H3 describe likely available alternate power resources to Klamath's hydroelectricity. The purpose of these sections is to 1) describe some of the resource options for replacing part or all of the project's generation, and 2) provide a second method for valuing the project's energy. This second method is the "most likely thermal alternative approach," discussed earlier.

Table D6.0-1 presents capital costs of alternative generation resources and is reproduced here for reference. The calculations assume replacements "specific to the project" and are based on a future capacity of 147.2 MW generating 697,043 MWh. The alternative resources would provide the same ratio of peak to non-peak power. Section H3 provides the assumptions used for each generation resource.

Table D6.0-1

Source	$/kW	Project Replacement ($ mil)	Annual Cost to Replace Project Power ($ mil)
Nat Gas	697	103	27.7
Cogen	917	135	31
Wind	1067	157	26.7
Coal	1754	258	21.6

Discussion and Comment
Energy Commission Staff question the assumption that if a new license were not granted, replacement energy will be needed that is "specific to the project." Loss of the relatively small capacity and energy values of the project could be more economically offset when larger thermal and renewable generation resources are constructed to serve projected load growth.

Even though the capital cost of alternate supply side resources seems high, PacifiCorp's calculations are more understandable than the market price simulation figure of $70 / MWh and annual value of $48.5 million. As discussed below, "the most likely thermal alternative" calculation seems to be at the high end of a reasonably expected range of estimates.

Comparison of PacifiCorp's Estimate of Alternate Power Resources to Estimates of the Northwest Council and the Energy Commission
For comparative purposes, the Energy Commission Staff presents two additional estimates for the capital costs for new generation. The first was prepared by the Northwest Power and Conservation Council and is contained in their 5th Draft Power Plan Wholesale Power Price Forecast. The second is drawn from the Energy Commission's Cost of Generation Report,[16] which was prepared as part of the 2003 Integrated Energy Policy Report.

Comparisons of Capital Costs for New Generation ($ / KW)

Energy Resource	PacifiCorp	NPCC 5th Power Plan - Table 2	CEC Cost of Generation Report (2004 In-Service Cost)
Natural Gas Combined Cycle	697	525	666*
Natural Gas Single Cycle	NA	600	577**
Cogeneration	917	NA	NA
Wind	1067	1010	1014
Coal	1754	1230	NA

* Cost of a combined cycle unit with a duct burner. Interconnection assumes a substation, costing $23,000,000, and 5 miles of transmission line.
** Figure assumes a substation cost of $3,000,000 and 3 miles of transmission lines.

For the Energy Commission calculation, Year 2004 in-service cost is the estimate of total capital costs to construct and begin operations for a power plant in the year 2004. This figure was selected in an attempt to provide an "apples-to-apples" comparison with PacifiCorp's cost estimate. In-service cost yields the highest cost estimate of the three possible cost categories described in the

[16] *Comparative Cost of California Central Station Electricity Generation Technologies* - California Energy Commission Staff Report, Publication No. 100-03-001. Placed on line August 8, 2003. (Acrobat PDF file, 124 pages, 540 kilobytes)

Energy Commission Cost of Generation Report (instant cost, installed cost, and in-service cost). The basic components of capital cost are component costs, land costs, permitting costs, interconnection costs, and environmental controls.

PacifiCorp's capital cost value seems high in comparison to the current Energy Commission cost estimate. Without knowing what values PacifiCorp uses for land, permitting, interconnection, environmental control costs, and financing assumptions, it is not possible to make a more definitive assessment of PacifiCorp's method. It seems that PacifiCorp did not assume using a combined cycle unit with a duct burner. Doing so would lower their capital cost, as well as their levelized cost of energy.

D. Availability of Replacement Power

Replacement thermal energy resources appear to be readily available at the local and regional level. According to the Oregon Department of Energy (Oregon DOE) Website,[17] PacifiCorp's PPM subsidiary has built a new 484 MW cogeneration natural gas plant and a 93 MW combustion turbine peaker project in Klamath Falls. The cogeneration plant is owned by the City of Klamath Falls. Two additional combined cycle natural gas plants totaling 1,600 MW are proposed in southern Oregon and are undergoing licensing review by Oregon DOE. PPM's 543 MW Klamath Generation Project is expected to be licensed by the end of 2004, while COB's 1,150 MW project is in the "contested evidentiary" phase.

At the regional scale, the Northwest Power and Conservation Council estimates that nearly 100,000 MW of new gas, coal, wind and solar capacity will be added to the Northwest Region by 2025.[18]

As PacifiCorp notes in Section H2.3, about $5.6 million in local transmission upgrades would be needed to ensure local reliability (Ex H at 2-7) in the event that replacement power is used for local demand.

Comments and Questions

PacifiCorp states in Section D6 that PPM energy is not available to PacifiCorp Utility customers, "Direct power transactions between PPM Energy and PacifiCorp are forbidden by code of conduct" (Ex D6 at 6-1). Please clarify if this policy holds only for the Klamath Cogeneration facility, or if it applies to all potential purchases of PPM energy by PacifiCorp as a utility under Oregon state law. Please document to whom energy from PPM energy facilities is sold if not is not available to PacifiCorp utility customers.

[17] *Oregon's Energy Facilities*, Oregon Department of Energy Website, ","
http://www.energy.state.or.us/siting/facility.htm, Reviewed April 19, 2004.
[18] Northwest Power and Conservation Council 5th Draft Power Plan at 3.

E. Consequence of License Denial and Reduction in Expenses if License Transferred

Sections D7, H2.3 and H2.4 discuss potential consequences of a license denial and cessation of energy generation from Klamath for local reliability, retail rates, and shareholders.

- "…denial of license application could lead to decommissioning to all developments of the Project. While this scenario is unlikely, such an action would have significant cost implications for PacifiCorp customers and investors" (Ex D at 7-1).

- "The denial of a license to PacifiCorp would result in increased electric rates for customers."

- "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 grid."

- "…loss of Project energy would have numerous effects on PacifiCorp's ability to serve the local demands in the Project area" (Ex H at 2-8).

Comment and Questions
The Energy Commission questions the assertions that loss of some or all of the Klamath project's energy would result in "significant costs" for PacifiCorp customers, shareholders or for the corporation. These assertions are not supported by data or supporting studies.

Please provide supporting data or studies that were used to reach the conclusion of "significant cost implications" and increased retail rates.

Did the decommissioning of Condit Dam in Washington result in increased retail rates or in significant cost increases for the Corporation or its shareholders?

Please specify and explain the "numerous effects" that loss of project energy would have on PacifiCorp's ability to serve local load in the Project area.

Part IV – Summary of Key Policy Issues and Energy Commission Staff Recommendations

In summary, the Energy Commission Staff recommends that FERC include full and partial decommissioning as project alternatives under NEPA and CEQA, given the benefits of restoring the Klamath River's salmonid fisheries. We also encourage FERC to direct PacifiCorp to provide estimates of the Klamath Project's energy in a manner that conforms with FERC regulation and guidance, and standard economic practice. Valuation of the project's energy is one of the most important elements in the relicensing review process because all environmental mitigation cost estimates, and the ultimate balancing of project costs and benefits, are referenced to this valuation of project energy.

Finally, we note that generation facilities in all sectors are regularly assessed by their owners to be sure they can be operated cost-effectively and in compliance with environmental regulation. Generation facilities are routinely retired when they are no longer economically competitive or environmentally efficient, or when the equipment has outlived its design life (natural gas, nuclear, wind turbines, etc

ATTACHMENT

"PRELIMINARY ASSESSMENT OF ENERGY ISSUES ASSOCIATED WITH THE KLAMATH HYDROELECTRIC PROJECT"

California Energy Commission Staff Report No. 700-03-007
May 2003

PRELIMINARY ASSESSMENT OF ENERGY ISSUES ASSOCIATED WITH THE KLAMATH HYDROELECTRIC PROJECT

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California Energy Commission

STAFF PAPER

MAY 2003
700-03-007

CALIFORNIA ENERGY COMMISSION

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State Of California | The Resources Agency of California

Memorandum

Date: May 5, 2003
Telephone: (916) 654-4996

To: Mary D. Nichols
Secretary for Resources

From: **California Energy Commission** - Robert L. Therkelsen
1516 Ninth Street
Sacramento, CA 95814-5512
Executive Director

Subject: **KLAMATH RIVER HYDROELECTRIC PROJECT ENERGY ISSUES**

The California Energy Commission staff have prepared the attached preliminary assessment of energy issues associated with the Klamath Hydroelectric Project as requested by the Resources Agency and the State Water Resources Control Board (SWRCB). It is our understanding that Resources Agency and the SWRCB seek to better understand the energy issues associated with a potential full or partial decommissioning of the project. We also understand that the Klamath River supported the third largest salmon runs on the Pacific Coast of the continental United States, and that restoration of this fishery is an important policy objective for the State. As part of the State's work to restore Klamath River salmon fisheries, Resources Agency and the SWRCB staff may propose to the Federal Energy Regulatory Commission (FERC) that dam removal alternatives be studied as part of the proceedings on renewal of the hydroelectric licenses for the facilities in PacifiCorp's Klamath Hydroelectric Project.

The Energy Commission staff's assessment indicates that, in terms of the potential impact to electricity resource adequacy, decommissioning one or more of the dams is a viable alternative that should be examined during the proceedings on the possible renewal of the FERC hydroelectric license. We recognize that more detailed technical studies will be conducted concerning the energy and other aspects of the Klamath project as the FERC proceeding moves forward. Energy Commission staff are prepared to provide additional help and support on energy issues to Resources Agency and the other participating agencies as the relicensing proceedings progress. If you have any questions on the enclosed report, please contact Kevin Kennedy (651-8836, kkennedy@energy.state.ca.us) or Jim McKinney (654-3999, Jmckinne@energy.state.ca.us) of my staff.

Attachment

California Energy Commission
PRELIMINARY ASSESSMENT OF ENERGY ISSUES ASSOCIATED WITH THE KLAMATH HYDROELECTRIC PROJECT

Summary

As requested by the California Resources Agency and the State Water Resources Control Board (SWRCB), Energy Commission staff has completed a preliminary electricity analysis of the possible decommissioning of one or more dams in the PacifiCorp Klamath Hydroelectric Project (FERC No. 2082). Staff's assessment indicates that, from the perspective of potential impacts to electric resource adequacy, decommissioning is a viable alternative that should be examined during the Federal Energy Regulatory Commission (FERC) proceedings on renewal of the hydroelectric license for these facilities. More detailed analyses of the energy and other aspects of the management of the Klamath system will be developed during the relicensing proceeding. That information will be needed for the parties to the proceeding to evaluate the balance among the competing goals and priorities, which include environmental protection and restoration, water supply, energy supply and reliability, and renewable energy use.

If one or more of the dams were decommissioned, replacement energy would be needed to offset foregone generation at these dams, and could be needed to address possible adverse effects on transmission system reliability at the local or utility level. This energy could be provided through local generation, transmission from PacifCorp's East Division, or purchased imports. New and proposed facilities in the vicinity are likely to address the need for local generation. These include a new 484 MW cogeneration facility that went into operation in Klamath Falls, Oregon, in 2001, and two applications for a total of over 1,500 MW in combined-cycle power plants in Klamath County currently before the Oregon Office of Energy for review. The time before the dams could be decommissioned would allow adequate time to address system-level generation needs and local transmission reliability issues. However, the cost to PacifiCorp of generating or purchasing power will be higher than for continued generation by these hydroelectric facilities.

When a more detailed technical evaluation of the energy impacts of decommissioning is needed, Energy Commission staff recommends it be completed by an energy consulting company with detailed local modeling capability. Energy Commission staff would be prepared to oversee that effort, including working to establish appropriate parameters and modeling assumptions for the study.

Introduction

As part of their work to restore California salmon fisheries, the Resources Agency and SWRCB will propose to FERC that dam removal alternatives be studied as part of the relicensing proceedings for PacifiCorp's Klamath Hydroelectric Project. PacifiCorp would then be responsible for completing an analysis of the energy, economic, and environmental effects of removing one or more dams on the Klamath River as part of the FERC proceedings. The Resources Agency and SWRCB asked Energy Commission staff to provide an initial review of the energy issues associated with a full or partial decommissioning of the project.

The analysis presented here is intended to provide preliminary answers to four questions: (1) What are the components of the Klamath Hydroelectric Project? (2) What is the projected electricity supply/demand balance in the relevant existing electricity forecasts? (3) Would decommissioning some or all of the dams in this project have potential effects on electricity resource planning? (4) How does the energy assessment fit into the larger balancing of interests in the management of the Klamath River basin and the overall Klamath relicensing process? This report does not provide detailed analysis or conclusions concerning these questions, but it is intended to provide a preliminary review based on available information.

This assessment is focused primarily on general characterizations of installed capacity and energy production for the four small hydroelectric plants owned by PacifiCorp located in California. These comments specifically do not address potential concerns about local reliability or effects on PacifiCorp ratepayers. Potential effects on resource adequacy for the utility are noted selectively, but have not been independently or comprehensively modeled or analyzed.

Primary data sources for this initial assessment include the PacifiCorp Integrated Resource Plan for 2003, information on the Klamath relicensing process from the PacifiCorp web site, the Oregon Office of Energy web site, the Northwest Power Planning Council preliminary reliability assessment for winter 2003 through 2006, the Energy Commission's most recent summer supply/demand forecast for 2003 through 2008, and the Energy Information Administration Annual Electric Utility Database. This assessment includes a preliminary estimate of the cost of foregone hydroelectric energy production for some decommissioning alternatives. The assessment does not attempt to estimate the environmental benefits or site-specific costs of dam removal, and does not consider the mitigation and enhancement measures that are likely to be required if the dams are relicensed. The assessment also does not consider the effect of removing these dams on the ability to meet the state's renewable energy goals.

Energy Commission staff has begun a preliminary analysis of the transmission system impacts of possible removal of these dams. Given the relatively small capacity of the projects in question, staff does not anticipate significant transmission issues would result from decommissioning some or all of dams that are part of this project, though limited transmission equipment upgrade or replacement would likely be required. As a first step in evaluating the transmission impacts, staff determined that the Energy Commission's information on the relevant portion of the transmission system was not up to date. Staff plans to conduct a power flow study of decommissioning once current transmission system information is received from PacifiCorp.

Klamath Basin Management

Energy production is one of a number of competing priorities for the management of the Klamath River basin. A recent water discharge permit from the North Coast Regional Water Quality Control Board for the Iron Gate fish hatchery listed the following fifteen beneficial uses of the Klamath River, not necessarily in priority order:

- municipal and domestic supply
- agricultural supply
- industrial service supply
- industrial process
- groundwater recharge
- freshwater replenishment
- hydropower generation
- water contact recreation
- non-contact water recreation
- warm freshwater habitat
- cold freshwater habitat
- wildlife habitat
- preservation of rare and endangered species
- migration of aquatic organisms
- spawning, reproduction, and/or early development

In the Klamath Basin, these competing demands for limited water supplies have made national news in recent years. In the past ten years, drought conditions beset farmers and fish in 1992, 1994, and 2001. Stakeholder factions have become more polarized and political in pursuit of their plans and priorities. In September 2002, an estimated 33,000 chinook salmon, coho salmon, and steelhead trout died in the lower Klamath River. Some blamed water diversions for irrigation as primary culprits, but post mortem scientific opinion is not unanimous. A January 3, 2003 report by the California Department of Fish and Game recognized many contributing factors, but concluded “flow is the only factor that can be controlled to any degree” (CDFG 2003, p. 52). In a paper published before that fish die-off, U.S. Geological Survey scientists modeled sophisticated water quantity and water quality obligations on the Klamath. They concluded that biological and contract requirements cannot be met in a dry year. Worse, meeting water quantity requirements as specified in Biological Opinions and FERC stipulations would still result in thermally impaired water bodies (Campbell et al. 2002).

Salmon and steelhead trout fisheries restoration is a major policy objective for the California Resources Agency, Department of Fish and Game, State Water Resources Control Board, CalFed, and their federal agency conterparts. Historically, the Klamath River had the third largest salmon runs on the Pacific Coast of North American, after the Columbia and Sacramento Rivers. Much of the salmon habitat within and above the project area is degraded, at least seasonally. Habitat improvement and restoration projects will be needed whether the Klamath dams are relicensed or decommissioned. Oregon’s Department of Environmental Quality identifies water bodies that do not meet federal Clean Water Act standards set in Section 303(d). In the summer months, Upper

Klamath Lake has water temperatures and dissolved oxygen levels that are lethal to threatened and endangered fish species. All reaches of the free-flowing river fail to meet the 303(d) standard for at least one listed parameter, water temperature. Other parameters of concern, especially in summer, include chlorophyll, toxics (ammonia), and pH. Especially below Copco, adverse water quality parameters include nutrients, organic enrichment, and low dissolved oxygen. "The poor health of the Basin's waters is not disputed. Once abundant fish populations have disappeared and others are threatened with extinction. The causes of these conditions and how they should be corrected, on the other hand, is fiercely debated" (OWRD 1999, p. 23). A report prepared for the U.S. Department of the Interior stated:

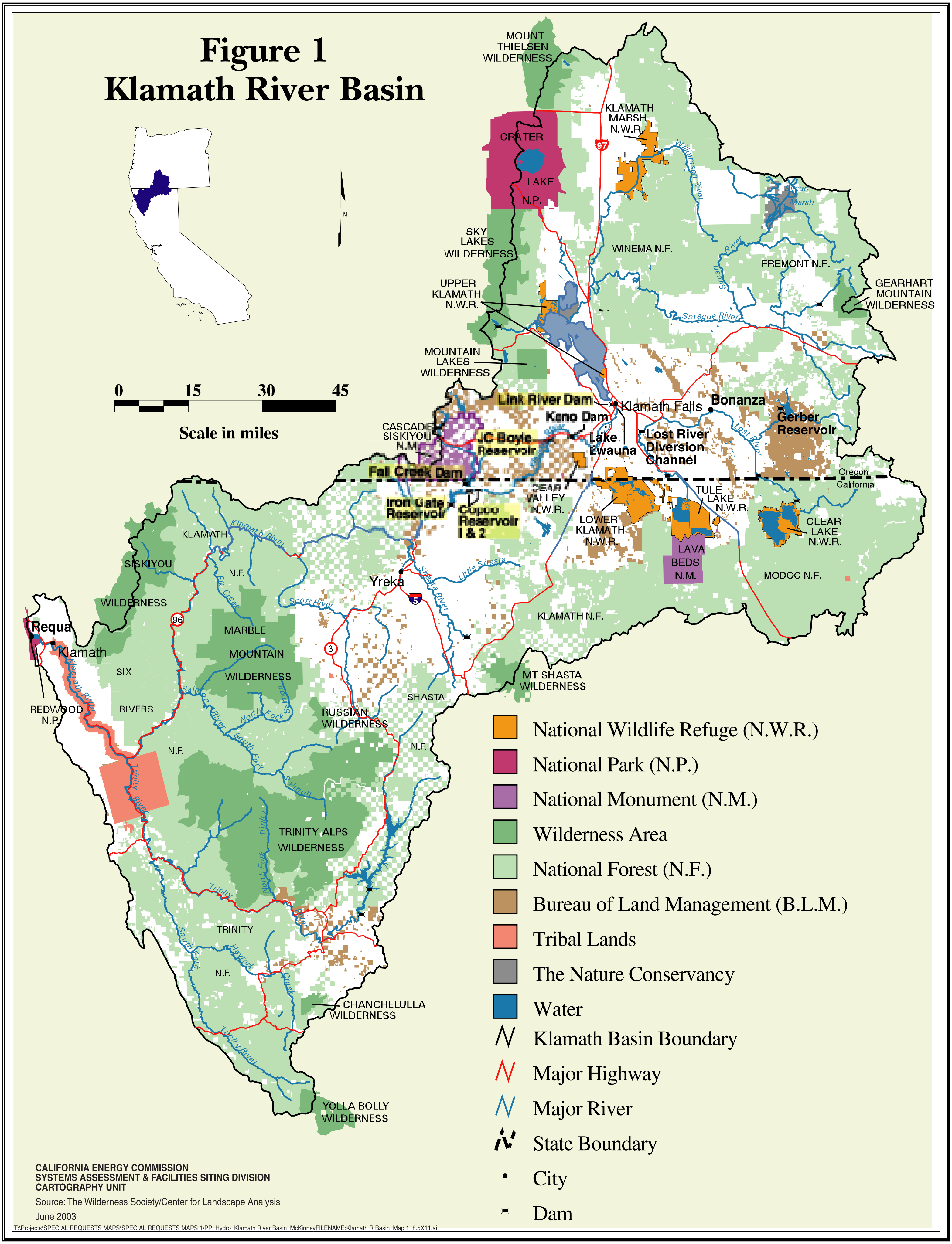
> "The decline of anadromous species within the Klamath River Basin can be attributed to a variety of factors which include both flow and non-flow factors. These include over harvest, effects of land-use practices such as logging, mining, stream habitat alterations, and agriculture. Other important factors have included climatic change, flood events, droughts, El Nino, fires, changes in water quality and temperature, introduced species, reduced genetic integrity from hatchery production, predation, disease, and poaching.
>
> "Significant effects are also attributed to water allocation practices such construction of dams that blocked substantial areas from upstream migration and have included flow alterations in the timing, magnitude, duration and frequency of flows in many stream segments on a seasonal basis" (Hardy and Addley 2001).

Klamath Hydroelectric Project

The Klamath Hydroelectric Project is a complex system that includes seven dams, including one on a tributary, Fall Creek, and seven powerhouses in two states, as shown on Figure 1. It was built from 1908 to 1962, developed jointly by the U.S. Bureau of Reclamation (USBR) and the California-Oregon Power Company (COPCO, the predecessor to PacifiCorp). In June 2003, PacifiCorp plans to file a draft application to renew their 50-year federal hydroelectric project license, which expires on March 1, 2006. This hydroelectric project is fully integrated with the Bureau of Reclamation's Klamath Project, which consists of 18 main canals totaling 185 miles, 516 miles of lateral canals, and 728 miles of drains (OWRD 1999, p. 18). Construction of that project lasted from 1905 to 1966.

PacifiCorp's Klamath Hydroelectric Project begins at Upper Klamath Lake in southern Oregon, where it operates the Link River facilities. The project area covers 64 river miles. Below the project, downstream from Iron Gate, the Klamath River is joined by the Shasta, Scott, Salmon and Trinity Rivers. On its 254-mile journey, the Klamath River flows south and west out of Oregon, through California's north coast ranges, reaching the Pacific in northern Humboldt County. Together with its tributaries, it drains an area of about 13,000 square miles.

Figure 1
Klamath River Basin



Hydroelectric Capacity and Annual Energy Production

The Klamath hydroelectric plants have a combined dependable capacity of 163 MW and an average annual energy output of 656.2 GWh, as shown in Table 1, with power plants listed from north (upstream) to south (downstream).

Table 1. Capacity and Energy Production from Klamath Hydroelectric Project

Powerhouse	Nameplate Capacity (MW)	Dependable Capacity[1] (MW)	Annual Energy (GWh)
East Side (Link River Dam)	3.0	3.0	12.1
West Side (Link River Dam)	1.0	0.0	3.9
J.C. Boyle	90.0	84.0	250.6
Oregon total	**94.0**	**87.0**	**266.6**
Copco 2	27.0	30.0	135.0
Copco 1	20.0	25.0	120.0
Iron Gate	18.0	19.0	123.0
Fall Creek	2.2	2.0	11.6
California total	**67.2**	**76.0**	**389.6**
Total	**161.2**	**163.0**	**656.2**

[1] Dependable capacity is the ability to provide sustained power for at least four to six hours (coincident with hours of peak demand), on a continuous daily basis.

Resource Adequacy

PacifiCorp operates two separate control areas, West (including portions of California, Oregon, and Washington) and East (including portions of Utah, Idaho, and Wyoming). The Klamath Hydroelectric Project is located in Oregon and California, and is part of PacifiCorp's West control area. While the transmission system in the Western United States is highly interconnected, any reliability concerns arising from decommissioning Klamath dams would most likely occur within the local PacifiCorp control territory. Information on current forecasts of the supply demand balance in California and the Pacific Northwest are presented below to provide a context for the consideration of decommissioning dams on the Klamath. Also presented below is information from PacifiCorp's 2003 Integrated Resource Plan. This plan assumes that the relicensing of PacifiCorp's hydroelectric facilities, including the Klamath Hydroelectric Project, will result in reduced generation capacity. However, the plan does not consider the PacifiCorp system at a level of detail that allows specific evaluation of the local effects of specific actions such as decommissioning dams on the Klamath River. A preliminary discussion of the local Klamath basin supply and demand balance is included below based on limited available information, but additional data gathering and analysis is needed to assess the local energy impacts of closure of these dams.

Regional Forecasts

On January 28, 2003, the Energy Commission staff released its current evaluation of the availability of electricity in California for the next few years.[2] This assessment concluded that the state's electricity demand and supply balance looks good through 2004. California appears to be in good shape in the near term in part because supply has outpaced demand in the Southwest and Northwest over the past two years by about 8,000 megawatts. In addition, 20 new power plants licensed by the Energy Commission have been constructed in recent years, adding 6,552 MW to the grid. The forecast for 2004 through 2008 shows declining reserve margins during that period due to the fact that the planning horizon for resource additions is usually only two to three years out.

From a California statewide perspective, the four California hydroelectric plants provide relatively small amounts of energy (averaging 389.6 GWh annually), from a combined 76 MW of dependable capacity. For California, which needs to add 1,200 MW or more in new generation supplies every year, adding or losing 76 MW by itself would not constitute a significant statewide impact. This fact does not consider local, regional, or service area effects on rates or reliability.

The Northwest Power Planning Council issued its current forecast for load growth in the Pacific Northwest during winter seasons through 2006 on January 14, 2003. According to the Council, reliability is reasonably assured only for this year, with a loss of load probability of under one-half percent. By winter 2004 through 2006, this probability increases to six percent for scenarios with no imports. With average imports into the Northwest (mostly from California), the loss of load probability remains small for two years, then climbs to five percent in 2006. In the Northwest, there is a growing concern about how to meet planning and operating reserve margins for 2006 and subsequent years.

These regional forecasts for the electricity demand and supply balance for California and the Pacific Northwest show declining reserve margins in coming years. New generation, transmission upgrades, increased conservation, and other activities will be needed to ensure that generation is adequate to meet load and that transmission system reliability is maintained. While reducing generation through decommissioning dams later this decade would contribute to declining reserve margins, the small capacity of the Klamath Hydroelectric Project compared to the scale of additional generation or

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[2] This evaluation was presented to the California Senate Energy, Utilities, and Communication Committee, and is available at the Energy Commission web site at http://www.energy.ca.gov/electricity/index.html#demand. This evaluation for the period through 2008 is the most recent update of the Energy Commission's *2002-2012 Electricity Outlook Report.*

reduced demand growth needed means that decommissioning will not have a significant reliability impact on a larger regional scale.

PacifiCorp Energy Resource Planning

PacifiCorp serves approximately 1.5 million retail customers in noncontiguous service territories covering portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. PacifiCorp has 53 hydroelectric plants in Oregon, Idaho, Utah, Montana, and California, with a total capacity of 1,119 MW (PacifiCorp 2003). The hydroelectric projects account for 13 percent of PacifiCorp's installed capacity, but produce (at a minimum) only six percent of its self-provided energy. More than 86 percent of PacifiCorp's self-provided energy comes from coal. Natural gas-fired plants provide about five percent. Most of PacifiCorp's hydroelectric generation resources are concentrated in its western division (Washington, Oregon, and California). PacifiCorp recognizes that the generating value of its hydroelectricity will diminish over time in both relative and absolute terms. In its Integrated Resource Plan, PacifiCorp notes that "the resources available to PacifiCorp to serve this demand will diminish over time as supply contracts expire, hydroelectric generation facilities are subjected to relicensing conditions and thermal plants comply with more stringent emissions requirements. This creates an imbalance that is referred to as the *gap*. This gap between loads and existing resources will grow through time…. While the exact size of this gap is uncertain, PacifiCorp expects it will require an additional 4,000 MW of new resources ([demand side management], generation, and supply contracts) through 2013" (PacifiCorp 2003, pp. 3-4).

PacifiCorp is presently a net importer of energy. Detailed energy sales figures are not readily available, but data from the Energy Information Administration shows that retail sales by PacifiCorp for 2001 totaled 47,708 GWh, with 18,125 GWh to customers in California, Oregon, and Washington (EIA 2001). In terms of buying energy to supply its customers, long-term purchases provided 11.8 percent of PacifiCorp's energy in 2002, while short-term and spot market purchases supplied 20.5 percent. The company's transmission system provides access to low-cost hydroelectricity from the Columbia River, including 389 MW presently under contract from three municipal utility districts in Washington. PacifiCorp currently purchases 925 MW from the Bonneville Power Administration and 104 MW from Qualifying Facilities.

Peak loads for the PacifiCorp's West control area can occur in summer or winter. "PacifiCorp forecasts load on its system to grow by 2.2% in the East and 2.0% in the West per year, on average" (PacifiCorp 2003, p. 3). PacifiCorp has adopted a 15 percent planning margin above peak load, similar to the Energy Commission's planning reserve. "The planning margin (15%) is the target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves and regulatory margin, and allow for demand growth uncertainty" (PacifiCorp 2003, p. 33). By 2004, PacifiCorp will have a gap of 1,200 MW between nameplate capacity of existing resources and its forecast 15 percent reserve margin, equal to approximately

14 percent of its projected existing resources.[3] This resource deficit grows to 4,100 MW by 2014, or approximately 52 percent of projected existing resources. "The gap between load and resources is perhaps the most distinctive and important feature of PacifiCorp's current position" (PacifiCorp 2003, p. 35). While Energy Commission staff has not independently reviewed these estimates, PacifiCorp is using the estimates to develop its plans for how to meet its resource needs over the next decade.

PacifiCorp has also modeled reduced hydroelectric capacity as one of the scenarios for its 2003 Integrated Resource Plan. The model assumes a loss of energy due to operational changes and increased bypass flows in the base case for all portfolios. A stress case was run to test the impact of losing just over 200 MW of hydroelectric-generation capacity, or 20 percent of their hydroelectric-generation portfolio.

In this scenario, PacifiCorp assumed that the reduced hydroelectric capacity would be replaced by two additional simple-cycle combustion turbines totaling 230 MW (PacifiCorp 2003, p. 135). According to PacifiCorp's evaluation, displacing existing renewable hydroelectric resources with new thermal peakers would:

- increase the present value of the revenue requirement (PVRR) by $608 million due to increase in capital and operating expenses;
- result in a $20 to $22 million increase in emissions costs contributing to the PVRR;
- result in a 16 percent increase in West market purchases, and an 8 percent decrease in West market sales;
- require new and existing combined-cycle combustion turbines and peakers in the West to run harder; and
- increase electricity transfers from the eastern portion of their territory to the western portion by 11 to 22 percent in 2014 over the base case results, and decrease transfers from the west to the east by 5 to 15 percent by 2014.

PacifiCorp concludes the analysis of this scenario by noting the value of hydro to the system resources, and that the Integrated Resource Plan assumes that all of the hydroelectric facilities PacifiCorp owns will be relicensed. PacifiCorp states that "detailed, plant-specific hydro analysis would be required to change this assumption. This will be done as plant relicensing occurs" (PacifiCorp 2003, p. 135). While Energy Commission staff has not reviewed PacifiCorp's scenario analysis presented above, staff does concur that detailed, plant-specific analysis should be conducted as part of the relicensing proceedings for the Klamath Hydroelectric Project.

Klamath Area Demands and Resources

Available information is not adequate to determine to what extent the Klamath Hydroelectric Project serves local load. During the May 7, 2002, relicensing plenary meeting for this project, an informal estimate for "local community" load was "maybe 750,000 MWh/year" (Klamath Relicensing 2002a, p. 5). The combined output from the seven hydroelectric plants averages 656,200 MWh/year, though this energy is not all

[3] PacifiCorp's projections of its existing resources for these purposes assume that none of its existing long-term contracts are renewed.

dedicated to meeting local load. Other local generation facilities include a 484 MW cogeneration plant in Klamath Falls operated by PPM Energy that went online in July 2001 (OOE 2002, 2003).   This project is designed to achieve a capacity factor over 90 percent, which would allow it to generate over 3,800,000 MWh/year. While its actual output will depend on a number of factors and could be much lower, this cogeneration facility has the ability to produce significantly more energy than the entire Klamath Hydroelectric Project produces or local customers consume. The cogeneration plant cost $300 million to build, and operates at 62 percent overall efficiency. A temporary 100 MW expansion of that project also went online in June 2002. PPM Energy, the non-regulated arm of PacifiCorp, has also purchased 237 MW of capacity to help supply the western control area grid of PacifiCorp. Most of the balance of PacifiCorp's and PPM Energy's generation is committed under long-term contracts to public and municipal utilities including Modesto Irrigation District, Seattle City Light, and Sacramento Municipal Utility District.

Two additional applications for projects in Klamath County are currently under review by the Oregon Office of Energy. PacifiCorp has proposed a 542 MW combined-cycle plant. This application was submitted for expedited review on December 26, 2001, though the request for expedited review was withdrawn on April 23, 2002, and the Office of Energy is reviewing the application under its standard process. COB Energy Facility, LLC, is also proposing building a 1,150 MW natural gas combined-cycle combustion turbine system in Klamath County. An application for this plant was submitted on September 5, 2002.

The addition of these new and proposed local generation facilities are likely to help PacifiCorp to address the identified gap between existing resources and peak system requirements with a planning margin. While the addition of the Klamath Cogeneration Project is already incorporated into PacifiCorp's projections and decommissioning of dams on the Klamath River would increase the size of the gap facing PacifiCorp system-wide, these new and proposed facilities make it very unlikely that local load or reliability problems would result.

Economic Value of Existing Hydroelectric Energy

Economic Evaluation Approach

An economic analysis of the possible decommissioning of some or all of the dams in the Klamath Hydroelectric Project would require detailed site specific information that was not available for this preliminary analysis. To be complete, such an analysis would need to evaluate the costs associated with decommissioning dams against the costs under various relicensing scenarios. The costs would include those associated with removal or modification of dams, restoration and mitigation activities, and the relative costs of electricity generation or purchase under various operating scenarios. In addition, any such economic analysis would need to be considered in the context of the environmental and resource costs and benefits of the different scenarios, which can be difficult to quantity in economic terms. While some additional site-specific analysis could be provided in the next few months if needed, a fuller exploration of these costs and benefits will likely have to be developed during the relicensing process itself.

In its Integrated Resource Plan, PacifiCorp notes that it agreed to decommission the Condit Dam near Mount Adams in Washington. The dam is 125 feet high, and stores water for a 14 MW powerhouse. PacifiCorp's summary of the balancing of costs and benefits that needs to be explored provides a useful context for considering these issues. For the Condit Dam, PacifiCorp determined that decommissioning was cheaper than adapting old facilities to meet new license requirements, which is a criterion PacifiCorp intends to apply elsewhere. Regarding mandatory conditions that go with re-licensing, PacifiCorp stated:

> "It is difficult to determine the economic impact of these mandates, but capital expenditures and operating costs are expected to increase in future periods while electricity losses may result due to environmental and fish concerns. As a result of these issues, for example, PacifiCorp has analyzed the costs and benefits of re-licensing the Condit Dam and has agreed to remove the Condit Dam at a cost of approximately $17 million" (PacifiCorp 2003, p. 27).

To provide a general economic context for consideration of decommissioning dams in the Klamath Hydroelectric Project, Energy Commission staff has completed a preliminary, 'back-of-the-envelope' estimation of the costs of generating or purchasing electricity to replace the foregone generation from the Klamath Hydroelectric Project. No attempt has been made to estimate either the costs of removing the dams or of possible mitigation or enhancement, including modified operations, that might be required should the dams be relicensed. For the limited purpose of this preliminary electricity assessment, staff assumed that existing hydroelectric energy production costs are less than 1 cent per kWh. An overhead cost of 0.8 cents/kWh can be posited, equal to $8/MWh or $8,000/GWh. Replacement energy can be estimated at 5 cents/kWh ($50/MWh or $50,000/GWh). These estimates have a high degree of uncertainty and some elements of risk associated with using the estimates. Baseload energy is likely to be cheaper, while peaking energy is likely to be more expensive.

California Hydroelectric Plants

On average, the four California plants generate 389.6 GWh per year. For this amount, the average yearly production costs would be approximately $3,116,800 (389.6 GWh x $8,000). At a wholesale price or replacement cost of $50/MWh, there would be an annual cost of approximately $19,480,000 to provide the same amount of energy now produced by PacifiCorp's California hydroelectric plants. For the value of foregone hydroelectric generation from the California plants, the net annual cost would be approximately $16.3 million.

J.C. Boyle Powerhouse, Oregon

Removing three dams at Iron Gate, Copco 1 and Copco 2, absent other changes, would create extremely varied flows on the Klamath River below J.C. Boyle powerhouse in Oregon. Except in spring months, when flows exceed 3,000 cfs, Boyle is operated to optimize generation during peak demand hours. At the dam, most of the water is diverted into a penstock, and supplied to the J.C. Boyle powerhouse located 4.3 miles down river. FERC has set a minimum flow of 100 cfs for the bypass reach between dam and powerhouse.

If J.C. Boyle powerhouse and dam were removed, in addition to removal of the California hydroelectric plants, an additional 20.7 miles of Klamath River would be reopened to salmon. Repeating the assumptions about the energy values cited above would yield these results. Boyle alone produces 250.6 GWh annually, on average. Assuming current electricity production costs at $8/MWh, operating and maintaining Boyle costs about $2 million per year. Replacement power at $50/MWh would cost $12.5 million per year. The net annual cost of foregone hydroelectric energy at Boyle would be $10.5 million.

To restore free-flowing conditions up to the base of Keno Dam, four dams would need to be removed: Iron Gate, Copco 1, Copco 2, and Boyle. Using the electricity production costs assumed above, the combined cost of foregone hydroelectricity production would be about $26.8 million each year.

Klamath Hydroelectric Project Management Priorities

Link River Dam

The upper end of the project is at Link River Dam, which controls the outlet of Upper Klamath Lake east of the Cascade Mountains. The dam is only 16.5 feet high, but it provides 93 percent of the active storage water for this project. The surface area of Upper Klamath Lake varies between 60,000 and 90,000 acres, making it Oregon’s largest lake, though the lake is very shallow, with an average depth of just over three meters in winter. In 1917, the USBR and the California-Oregon Power Company signed a contract to build Link River Dam. Construction of a reinforced concrete-slab began in 1920, and finished in 1921. The USBR owns this dam, and controls the release of water by dictating flow schedules to PacifiCorp, the dam operator. For Link River Dam, energy production is fourth priority. The top priorities for managing the dam are: 1) maintaining Upper Klamath Lake elevations to meet Biological Opinion requirements; 2) provide needed downstream flows in the Klamath River below Iron Gate Dam; and 3) divert water supplies to USBR’s Klamath Irrigation Project.

Both ends of Link River Dam have headgates for canals leading to power plants. The East Side Powerhouse generally runs continuously on 975 cfs fed by a 1-mile canal, with a 1,200 cfs maximum capacity. In this bypass reach, locally called Link River, minimum instream flows are 90 cfs. The West Side Powerhouse operates intermittently on a maximum 250 cfs, fed by a 1.2-mile canal. West Side only generates when releases from Upper Klamath Lake exceed 1300 cfs.

Keno

Keno Dam was built in 1967 by PacifiCorp to generate electricity, but generation facilities were never installed. The concrete Keno dam is just 26 feet high, and creates a reservoir 20.1 miles long. Keno Reservoir (Lake Ewauna) immediately captures water discharges from East Side and West Side powerhouses. Keno Dam is operated to "re-regulate" river flows. Lake level fluctuates less than 0.5 foot. Adding generating capacity to Keno to supply some replacement power is among the alternatives that the National Marine Fisheries Service has recommended for study. Below Keno Dam, the river flows freely for 5 miles.

J. C. Boyle

The earthen dam J. C. Boyle is 68 feet high. Built in 1958, it created a reservoir 3.3 miles long. At the dam, most of the flow is diverted to penstocks and delivered to the powerhouse 4.3 miles down river. Minimum flows in this bypass reach are 100 cfs to 350 cfs, depending on the season.

At the J.C. Boyle powerhouse, "the first priority is to meet biological and environmental objectives" (Klamath Relicensing 2002a, p. 3). For a typical day at J.C. Boyle, "Our peak at this time is 7-10 [am] and anticipating 6-10 pm. We focus on the morning peak at J.C. Boyle, [then] back down to 100 cfs" (Klamath Relicensing 2002a, p. 3). When asked about flexibility for shaping generation to meet hourly loads, a PacifiCorp manager replied "When we're the most sensitive? The morning customer load, we're following a load shape every day. It's understood that in the summer and winter you're exposed to peak events. It would be to our advantage to have more flexibility in the summer and winter" (Klamath Relicensing 2002a, p. 4).

From the Boyle powerhouse, the Klamath River flows 11 miles to the California border. This stretch has popular Class IV and V whitewater rapids, and was given National Wild and Scenic River status in 1994. Once in California, water flows 5.4 river miles to Copco 1 reservoir, and another 5.4 miles to the dam.

Copco 1 and 2

The concrete arch dam at Copco 1 is 230 feet high and lacks any fish passage facilities. When it was built in 1917, it permanently ended fish passage to the Klamath Basin. The powerhouse is adjacent to the dam, and is not constrained by limits on reservoir fluctuation, ramp rates, or instream flow releases. "Copco 1 is generally scheduled and operated in a peaking mode.… One or both of the turbine-generators are typically started in the morning to early afternoon and ramped up to best efficiency or full load output" (PacifiCorp, Draft description of reach 7, Copco 1 Reservoir, FERC Project No. 2082). From here, water flows 1.5 miles down river to a small reservoir (73 acre-feet), Copco 2. This reservoir was created by a concrete gravity dam, 33 feet high, built in 1925. Copco 2 powerhouse is also operated to provide peak power. Water discharged from Copco 2 immediately enters Iron Gate Reservoir, 6.8 miles long.

Iron Gate

Iron Gate Powerhouse is located at Iron Gate Dam. The dam is 173 feet high, rock-filled with a compacted clay core. It was built in 1962. By design and current operation, the dam's primary purpose is to smooth out and "re-regulate" flows released immediately upstream by the Copco plants. Energy production at Iron Gate is second priority, and will likely fall to third or fourth place after relicensing. From Iron Gate, the Klamath River flows unchecked for 190 miles to the ocean. The FERC-stipulated minimum flow releases are 1,300 cfs from September through April, 1,000 cfs in May and August and 710 cfs in June and July. The record discharge at the mouth of the Klamath River was 557,000 cfs on December 23, 1964, during a major flood.

Conclusions

Energy Commission staff's assessment indicates that, in terms of the potential impact to electricity resource adequacy, decommissioning one or more of the dams is a viable alternative that should be examined during the proceedings on the possible renewal of the FERC hydroelectric license. More detailed analyses of the energy and other aspects of the management of the Klamath system will be developed during the relicensing proceeding. That information will be needed for the parties to the proceeding to evaluate the balance among the competing goals and priorities, which include environmental protection and restoration, water supply, energy supply and reliability, and renewable energy use.

If one or more of the dams were decommissioned, replacement energy would be needed to offset foregone generation at these dams, and may be needed to address possible adverse effects on transmission system reliability at the local or utility level. This energy could be provided through local generation, transmission from PacifCorp's East Division, or purchased imports. New and proposed facilities in the vicinity are likely to address the need for local generation. These include a new 484 MW cogeneration facility that went into operation in Klamath Falls, Oregon, in 2001, and two applications for a total of over 1,500 MW in combined-cycle power plants in Klamath County currently before the Oregon Office of Energy for review. Energy Commission staff has not completed a detailed assessment of the potential effects on reliability at the local or utility level, but given the time before the dams could be decommissioned would allow adequate time to address system-level generation needs and local transmission reliability issues. However, the cost to PacifiCorp of generating or purchasing replacement energy will be higher than for continued generation by these hydroelectric facilities.

Regardless of the hydroelectric outcomes on this project, PacifiCorp will need additional generation over the next decade to meet load. PacifiCorp will need to add about 4,100 MW of new capacity to be built, secured by contract, purchased in short-term markets, or offset by demand-side management and energy efficiency programs. In addition to PacifiCorp's need for additional generation, both California and the Pacific Northwest area will also need additional generation over the next decade to meet load. From the perspective of the larger western systems, replacing 76 to 163 MW of existing PacifiCorp hydroelectric capacity with additional new thermal resources would not have a demonstrably significant effect on resource adequacy.

When a comprehensive technical study is needed, Energy Commission staff recommends it be undertaken by an energy consulting company with detailed local modeling capability. Energy Commission staff can coordinate that effort, including assisting in developing the parameters and modeling assumptions for the study. Such a study would include modeling of potentially needed replacement alternatives for energy, capacity, and transmission; local and regional reliability concerns; and utility and ratepayer costs. This study would include characterizations of PacifiCorp's supply-demand balance for its service territory and customer base during the period when decommissioning may occur. A detailed study of these concerns, and of transmission capacity in the Klamath Basin area for replacement power, would enable authoritative testimony to be provided as inputs to the FERC proceedings.

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