ECONOMIC MODELING OF RELICENSING AND DECOMMISSIONING OPTIONS FOR THE KLAMATH BASIN HYDROELECTRIC PROJECT

CONSULTANT REPORT

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ABSTRACT

The Klamath River is one of the most important rivers for imperiled populations of Chinook salmon, coho salmon and steelhead trout on the West Coast of the United States. PacifiCorp's 169 megawatt Klamath Hydroelectric Project is a major contributor to the extirpation of salmon from over 300 miles of habitat in the upper Klamath Basin. The Federal Energy Regulatory Commission is reviewing the project's existing Federal Power Act license and will impose mitigation measures to reduce environmental impacts if it issues a new license. Decommissioning the project and replacing its electricity from other sources may be more cost effective than relicensing the project and installing fish ladders and water quality improvement devices to meet modern legal and scientific standards.

Staff from the California Energy Commission and U.S. Department of Interior Office of Policy Analysis have collaborated with Dr. Richard McCann of M.Cubed to conduct a rigorous economic analysis of the relicensing and decommissioning options.

The study finds that the relicensing option, which includes the installation of fish ladders and other mitigation measures, could reduce hydroelectric generation by 23 percent and cost between $230 and $470 million in 2005 dollars over a 30-year period. In contrast, the decommissioning option, which includes removing four hydropower dams and replacing the power for 30 years, could cost between $152 and $277 million. Compared to the relicensing option, the decommissioning option could range from costing PacifiCorp ratepayers $14 million to saving them $285 million over a 30-year period, based on the scenarios and uncertainties incorporated into this analysis. Based on assumptions for the midline case, and using PacifiCorp's estimate for replacement power costs, decommissioning would be $101 million less costly than relicensing.

KEY WORDS

Economic analysis, decommissioning, relicensing, hydroelectric project, Klamath River, salmon

ACKNOWLEDGMENTS

The California Energy Commission staff and U.S. Department of Interior's Office of Policy Analysis have collaborated to produce this economic analysis of Klamath River Hydro Project options. This analysis has been made possible by the extensive collaboration between state and federal energy, fish and wildlife, and water quality agencies, including the California State Water Resources Control Board, California Department of Fish and Game, California Coastal Conservancy, Oregon Department of Energy, U.S. Fish and Wildlife Service, U.S. Bureau of Reclamation, U.S. Bureau of Land Management, and NOAA Fisheries.

The lead author and economic modeler for this study is Dr. Richard McCann, a principal with M.Cubed. Dr. James D. Fine of M.Cubed also contributed to the report. Nancy Parker of the Bureau's Technical Services Center was the principal hydrologic modeler.

The core team of analysts for this report include David Diamond and Robert Berman from Interior's Office of Policy Analysis, Jim McKinney of the Energy Commission's staff, and Dr. Richard McCann of M.Cubed. Key contributors include Michael Bowen from the Coastal Conservancy for the decommissioning studies and David Stewart-Smith with the Oregon Department of Energy. Russ Kanz of the California State Water Resources Control Board, and Don Koch and Annie Manji from the California Department of Fish and Game, helped initiate the energy analyses of the Klamath Hydro Project. Board Member Art Baggett of the State Water Resources Control Board provided critical support for this study from its inception through its development.

Dora Gomez, Angela Hockaday and Marci Errecart at the Energy Commission assisted with formatting and report production.

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EXECUTIVE SUMMARY

The Klamath River is one of the largest and most important rivers for salmon in California and Oregon. It provides habitat for several runs of imperiled Chinook salmon, Coho salmon and steelhead trout. A 169 megawatt (MW) hydropower project consisting of four main dams and powerhouses, operated by PacifiCorp, has been a major contributor to the extirpation of salmon from over three hundred miles of habitat in the upper Klamath basin. The hydro project contributes to significant, ongoing impacts to native salmon and trout populations and to water quality. Populations of Klamath Chinook salmon reached such critically low levels in 2006 that the entire Pacific Coast commercial salmon fishery in northern California and southern Oregon was severely curtailed in order to protect the adult salmon returning to spawn in the Klamath River.

The current Federal Energy Regulatory Commission (FERC) relicensing proceeding will determine if and under what terms a new license should be granted to PacifiCorp to continue operating the Klamath Hydro Project (FERC Project No. 2082) under the Federal Power Act, and in accordance with Endangered Species Act and Clean Water Act. The Klamath Hydroelectric Project, parts of which are almost 90 years old, does not meet current environmental regulatory and legal standards. Substantial facility upgrades and mitigation measures such as fish ladders, water quality control devices, and new limitations on project operations could be required to provide for upstream and downstream salmon migration and to bring the project into conformance with current environmental standards. As an alternative to such potentially substantial mitigation measures, it may be more cost effective to decommission the hydro project, procure its electricity from other sources, and restore the river's aquatic habitat.

The California Energy Commission (Energy Commission) staff, U.S. Department of Interior's Office of Policy Analysis (Interior) and numerous other state and federal energy and wildlife agencies in Oregon and California have collaborated to analyze and compare the net economic costs for the relicensing and decommissioning scenarios. The objective has been to design and conduct a rigorous, objective and transparent analysis that can be used by government agencies and stakeholders in the FERC Proceeding, settlement negotiations, and regulatory proceedings at the Oregon and California Public Utilities Commissions.

Dr. Richard McCann of M.Cubed is the primary author for this report. Under contract to the Energy Commission, he developed the conceptual framework and Klamath Project Alternatives Analysis Model (KPAAM) to analyze the costs for the two scenarios. Nancy Parker, a hydrologist with the U.S. Bureau of Reclamation's (Bureau) Technical Services Center, developed the hydrologic model. Cost inputs for the mitigation measures and decommissioning were obtained from filings in the FERC relicensing proceeding from PacifiCorp, and state and federal agencies. Replacement power cost estimates were obtained from independent, publicly available sources in the Pacific Northwest and California.

Background

The Klamath Hydroelectric Project currently totals 169 MW nameplate capacity from four main power dams; JC Boyle, Copco I and II, and Iron Gate. FERC rates the project's dependable capacity at 42.7 MW. Current average annual generation is estimated to be about 716,800 megawatt-hours (MWh). Although generally portrayed as a peaking facility, the project operates more as a run-of-river facility due to a number of constraints. In its recent General Rate Case filings before the California Public Utilities Commission (CPUC), PacifiCorp acknowledges that it has little authority or operating discretion to dispatch the Klamath Project to meet electricity demands. The hydro project has no large storage reservoir capacity available for seasonal dispatch, and inflows from the Bureau's irrigation project at Upper Klamath Lake are governed by two recent Biological Opinions issued under the Endangered Species Act to protect threatened salmon and other fish species.

PacifiCorp serves about 1.6 million customers across six Western states. Total electricity sales in 2004 were 62,086 gigawatt-hours (GWh). PacifiCorp's forecasted peak load for 2006 is 10,090 MW. The company owns 8,419.5 MW of generating assets. Based on its *2006 Update to its Integrated Resource Plan*, PacifiCorp plans to invest $2.3 billion to develop 2,413 MW of new generating, transmission and demand side management resources by 2014. At the systems level, the Klamath Hydro Project comprises two percent of total capacity, and contributes about one percent to total electricity sales.

Summary of Results

Hydrologic Model Results

The Bureau's Technical Services center developed a hydrologic model to simulate the potential for meeting system operating criteria for Current Conditions and Relicensed Conditions given a set of hydrologic inputs. The model estimated the amount and timing of electricity generation that would be available under a Relicensing Condition, and that would need to be replaced under the Decommissioning Condition. The preliminary mandatory flow conditions for relicensing as described by the U.S. Bureau of Land Management (BLM) under Section 4(e) of the Federal Power Act were used to set the instream flow releases and ramping rates for the future Relicensing Condition case. Water quality mitigation measures may add additional operational constraints when formulated.

- Imposing the Relicensing Conditions reduces the Current License Condition baseline generation 23 percent to 562,790 MWh. These conditions also further constrain the project's flexibility to operate in a peaking dispatch mode and represents the amount of electricity that would be lost if the Klamath Project were decommissioned.

Klamath Project Alternatives Analysis (KPAAM) Model Methodology

KPAAM is an Excel spreadsheet model that is used to compare economic and financial costs of Klamath Project relicensing and decommissioning. The model integrates hydrologic simulations from current and future operational and decommissioning scenarios, future generation levels under numerous operational scenarios, cost inputs for comprehensive mitigation should the project remain in place, decommissioning cost estimates, and replacement power cost estimates from a range of publicly available wholesale price forecasts. The primary model outputs are cost comparisons of the relicensing and decommissioning scenarios across ranges of mitigation cost estimates and replacement power cost estimates. All results are presented in constant 2005 dollars (2005$). KPAAM is not a cost-benefit model in that it does not attempt to quantify or monetize the natural resource benefits, or other social costs and benefits, associated with each alternative case.

Relicensing Condition with Agency-Mandated and Recommended Mitigation

Costs for over 160 mandatory and recommended mitigation measures were compiled from the March 29, 2006 FERC filings from PacifiCorp, and state and federal agencies. Proxies are used for the water quality measures necessary to meet Section 401 of the Clean Water Act, since they have not yet been prepared by the California and Oregon water quality agencies. Most of the flow-related measures were captured in the hydrologic modeling results.

Relicensing Condition mitigation measures include:

- **Fish Passage Conditions** for full volitional upstream and downstream passage past four power dams (fish ladders), spillway and tailrace improvements, and hatchery operations.
- **Non-fish Passage Conditions** such as gravel augmentation, riparian restoration, terrestrial resource protection, recreational enhancements, and cultural resource protection.
- **Water Quality Conditions** to comply with water quality standards per section 401(e) of the Clean Water Act, including installation of oxygen diffusers at Iron Gate, and temperature control devices at Iron Gate and Copco 2. Since water quality measures to meet Section 401 of the Clean Water Act have not yet been prepared by the California and Oregon water quality agencies these estimates are proxies.

The complete list of measures included in the Relicensing Condition is included in Appendix B.

Table ES-1: Net Present Values of Relicensing Mitigation Costs (Millions of 2005 Dollars)

	Low	Midline	High
Fish Passage Conditions	$190	$270	$350
Nonfish Passage Conditions	$20	$20	$30
Water Quality Conditions	$20	$70	$90
Total Mitigation Costs	**$230**	**$360**	**$470**

Table ES-1 shows that the total net present value of capital, operations and maintenance costs over a 30-year license period would range from $230 to $470 million, with a midline estimate of $360 million. The engineering costs estimates are subject to some uncertainty, and it is not possible to know exactly which mitigation conditions FERC would include in a new license. Accordingly, a 30 percent uncertainty factor is added to either side of the midline case.

Over the 30-year license period, the relicensing mitigation measures would add $30 to $61 per MWh to the existing production costs for the Klamath Hydro Project. Current production costs are estimated to be $19 per MWh. Using results for the midline case, production costs would increase by $47 per MWh and total $66 per MWh for the Relicensed Condition.

Decommissioning Condition

The Decommissioning Condition developed for KPAAM assumes removing the Boyle, Copco I and II, and Iron Gate dams and powerhouses.[1] Decommissioning would occur between 2013 and 2015. Existing license conditions for operations and generation are assumed to continue until decommissioning, although interim measures may be developed. The two main costs for the Decommissioning Condition are dam removal and replacement power.

Dam Removal: The modeling team used a dam removal cost estimate developed for the California Coastal Conservancy that was most recently updated in September 2006. The nominal dollar estimate is $89.6 million. A more detailed decommissioning study is underway by the Conservancy and its consultant Gathard Engineering and Construction. These revised cost estimates can be added to future KPAAM scenarios when available.

Replacement Power: Estimates for replacement power costs are derived for a 30-year period from 2008 to 2038. The modeling team identified six publicly available wholesale price forecasts that are intended to cover a reasonable range of assumptions and scenarios used by energy planning agencies and utilities. Estimates are presented as 30-year levelized costs in 2005 dollars to allow for “apples to apples” comparisons.

Energy Forecast	$ / MWh
PacifiCorp July 2005 Avoided Cost Filing - Oregon PUC	$66.10
US Dept. of Interior March 2006 FERC Filing	$37.00
Northwest Power Planning Council 5th Power Plan	$44.59
DOI + PacifiCorp Avoided Cost + EIA Gas Price	$45.25
Oregon Dept of Energy: Biomass + DSM	$58.18
CPUC Market Price Referent: Combined Cycle Gas	$79.44

[1] Keno Dam, a non-generating facility, is assumed to remain in place in this analysis.

Net Present Value Costs for the Decommissioning Condition

KPAAM calculates the net present value (NPV) of the various cost components for the Relicensing Condition and Decommissioning Condition alternatives. Total 30-year net present values for decommissioning and replacement power costs are presented in Table ES-2. Total 30-year net present value costs for relicensing with mitigation are also shown for reference. Using PacifiCorp's forecast for replacement power costs and the midline case for decommissioning costs, decommissioning with replacement power would cost $259 million, but could range between $242 and $275 million.

Table ES-2: Total Costs of Decommissioning: Dam Removal plus Replacement Power (Millions of 2005 Dollars)

	Total Decommissioning Costs	***Low***	***Midline***	***High***
		$77	*$94*	*$110*
Replacement Power Cost Forecast	**30-Year Total Replacement Power Costs**	**Replacement Power plus Dam Removal Costs**		
		Low	**Midline**	**High**
US DOI	$74	$152	$168	$185
US DOI-PacifiCorp+EIA	$99	$176	$192	$209
NWPPC 5th Power Plan	$108	$185	$201	$218
Oregon DOE	$125	$202	$219	$235
PacifiCorp 2005	$165	$242	$259	$275
CPUC MPR	$167	$244	$260	$277
Relicensing Mitigation Costs		*$230*	*$360*	*$470*

Klamath Project Alternatives Analysis (KPAAM) Model Results

KPAAM calculates the net differences between the Relicensing Condition and the Decommissioning Condition. Total Decommissioning and Replacement Power costs are subtracted from total Relicensing costs. A positive value indicates that decommissioning costs less than relicensing. Parentheses and dark shading denote a negative value. Results are shown for the six replacement power cost estimates used in the model, and for low, midline and high decommissioning cost estimates

Table ES-3: NPV of Relicensing Minus Dam Removal plus Replacement Power Costs by Replacement Power Cost Scenario (Millions of 2005 Dollars)			
Replacement Power Cost Forecast	**Low**	**Midline**	**High**
US DOI	$78	$192	$285
US DOI-PacifiCorp+EIA	$54	$168	$261
NWPPC 5th Power Plan	$45	$159	$252
Oregon DOE	$28	$141	$235
PacifiCorp 2005	($12)	$101	$195
CPUC MPR	($14)	$100	$193

- In most cases, KPAAM results show that it is less costly to decommission the Klamath Hydro Project and replace its electricity than to relicense it and install the required mitigation measures. Nearly all 18 values across the three cost scenarios and six replacement power cost estimates are positive. Two values are negative, where relicensing and decommissioning costs are at the low end of the range and forecasted replacement power costs are at the upper end of the range. From the perspective of PacifiCorp's ratepayers, the range in net cost differences between the two scenarios is from $14 million more for decommissioning to $285 million less for decommissioning. Using PacifiCorp's power cost estimate from its 2005 Avoided Cost Filing with the Oregon Public Utilities Commission, the midline case shows that it would be $101 million less costly for PacifiCorp's ratepayers to decommission the project rather than relicense it. The range is from a potential savings of $12 million to a potential cost of $195 million.

Interpretation and Conclusions

The Klamath Project is small compared to the total power requirements of PacifiCorp's customers and to the systems-level scale of new generation needed to meet load, reserve margins and transmission system reliability in the utility's service territory. In its 2003 *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, staff from the Energy Commission concluded that decommissioning some or all of the Klamath facility was a feasible alternative that should be further examined during relicensing. Given the size of the PacifiCorp system, the relatively large amount of capacity and energy already procured (approximately 22 percent), and the amount of additional capacity and energy needed to meet projected load growth, the report also concluded that loss of the Klamath Hydroelectric Project "would not have a demonstrably significant effect on resource adequacy."

PacifiCorp's energy planners are also assessing how to replace the energy and capacity from the Klamath Project. The August update to its Preferred Portfolio in the *2006 Integrated Resource Plan* identifies "Replace Klamath hydro units with alternative resources." According to PacifiCorp's Final License Application to FERC, local transmission improvements totaling $5.6 million could allow replacement power to be brought in from the grid. Since 1999 PacifiCorp has decided to remove dams totaling 28.5 MW of capacity at four other FERC-licensed projects rather than retrofit existing facilities as a condition of operating under new licenses.

Power plants are routinely retired when they are no longer economically competitive or environmentally compliant (e.g., a coal-fired generator may be retired if there is a new requirement for a scrubber, and replacing the generation may be less costly than retrofitting the old plant), or when the equipment has outlived its design life (natural gas, nuclear, wind turbines, etc). For example, in the state of California 3,810 MW has been retired for various reasons since 2001. The Klamath Project is relatively small compared to the type of large thermal plants that have been retired in California.

From a review of the PacifiCorp filings with FERC and with the Public Utility Commissions in Oregon and California, it is apparent that the Klamath Hydro Project primarily serves as a low cost energy resource with little firm capacity or peaking dispatch flexibility. This type of replacement energy is readily available from other PacifiCorp generating resources and from the grid. In a brief to the California Public Utilities Commission, PacifiCorp explains that it uses Klamath energy, when available, to displace higher cost, fossil generation. In its Final License Final License Application to FERC, PacifiCorp states that if generation were to cease at Klamath it would still be able to service its local customers.

The Klamath Hydro Project is a low cost energy resource because it does not have modern mitigation measures to ensure fish passage or water quality. As shown in KPAAM, adding these measures would increase production costs by $30 to $61 per MWh and would total $230 to $470 million over 30 years. However, the 169 MW Klamath Project would still be an intermittent, low capacity, inflexible energy resource with 23 percent lower production levels. For the midline case, decommissioning the project and procuring 30 year's worth of replacement electricity for PacifiCorp's customers would cost $259 million – and would be $101 million less costly than relicensing the project – if PacifiCorp's own estimate for replacement power is used. In comparison, a new 500 MW natural gas-fired combined cycle power plant—about three times larger than the Klamath Project—that meets all State of California air quality standards can be constructed for $350 million to $400 million. Facilities such as these provide firm capacity and peaking dispatch flexibility for nearly all of their nameplate capacity throughout their design life.

PacifiCorp's ratepayers in six states will have to pay either to relicense the project and install substantial mitigation measures, or to decommission the project and procure replacement power elsewhere. The status quo operations will continue only until a regulatory decision is made. This application of KPAAM demonstrates that decommissioning the Klamath Hydro Project would create net economic benefits for

PacifiCorp’s ratepayers. Decommissioning also creates the potential for restoring salmon runs to one of the most important remaining salmon rivers on the West Coast.

CHAPTER 1: INTRODUCTION AND OVERVIEW

The Klamath River is one of the largest and most important rivers for salmon in California and Oregon. It provides habitat for several runs of imperiled Chinook salmon, Coho salmon and steelhead trout. Populations of Klamath Chinook salmon reached such critically low levels in 2006 that the Pacific Coast commercial salmon fishery was severely curtailed in southern Oregon and northern California in order to protect adult salmon returning to spawn. A hydropower project operated by PacifiCorp has led to the extirpation of salmon from over three hundred miles of habitat in the upper Klamath basin. It causes significant, ongoing impacts to native salmon and trout populations and to water quality. Despite environmental degradation from the dams and other resource uses over the past century, the Klamath River has not been as highly developed as other major western salmon rivers like the Columbia and Sacramento. Accordingly, it offers a unique potential for successful restoration of the imperiled salmon runs.

A critical decision for PacifiCorp, regulatory agencies, Indian Tribes and stakeholders is whether to invest in modifications to the Klamath Hydroelectric Project facilities and modify its operations in order to allow for full upstream and downstream salmonid migration, or to decommission the dams and powerhouses and restore the aquatic habitat. This public policy decision is under evaluation as part of the Federal Energy Regulatory Commission (FERC) proceeding to determine if, and under what conditions, a new license should be granted to PacifiCorp to continue operating the Klamath Hydro Project (FERC Project No. 2082) under the terms of the Federal Power Act. It is also being evaluated in settlement negotiations between PacifiCorp, government agencies, Tribes and stakeholders.

The California Energy Commission (Energy Commission) staff and U.S. Department of Interior's Office of Policy Analysis (Interior) have collaborated on analyzing the energy and costs issues for these alternative project futures. It is one of the first – and possibly the first – independent interdisciplinary analyses to integrate environmental mitigation measures and costs with electricity supply and replacement power costs for a hydroelectric project. This analysis has been made possible by the extensive collaboration between state and federal energy, fish and wildlife, and water quality agencies, including the California State Water Resources Control Board, California Department of Fish and Game, California Coastal Conservancy, Oregon Department of Energy, U.S. Fish and Wildlife Service, U.S. Bureau of Reclamation, U.S. Bureau of Land Management, and NOAA Fisheries. The technical analytic work has been performed by M.Cubed of Davis, California (under contract to the Energy Commission[2]) and the Bureau of Reclamation's Technical Service Center in Denver, Colorado (under an internal agreement with the Department of Interior).

The lead author and economic modeler for this study is Dr. Richard McCann, a principal with M.Cubed. Dr. James D. Fine of M.Cubed also contributed to the report. Nancy Parker of the Bureau's Technical Services Center was the principal hydrologic modeler and author of the hydrologic analysis presented in Chapter 2.

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[2] California Energy Commission Contract No.700-05-002 totaling $58,500, as of the date of this report.

The core team of analysts for this report include David Diamond and Robert Berman from Interior's Office of Policy Analysis, Jim McKinney of the Energy Commission's staff, and Dr. Richard McCann. Key contributors include Michael Bowen from the Coastal Conservancy for the decommissioning studies and David Stewart-Smith for the Oregon Department of Energy. Russ Kanz of the California State Water Resources Control Board and Don Koch and Annie Manji from the California Department of Fish and Game helped initiate the energy analyses of the Klamath Hydro Project. Board Member Art Baggett of the State Water Resources Control Board provided critical support for this study from its inception through its development.

The alternative futures for the Klamath Hydro Project are evaluated and compared using an Excel spreadsheet-modeling platform named Klamath Project Alternatives Analysis Model (KPAAM). The model integrates hydrologic simulations from current and future operational and decommissioning scenarios, future generation levels under numerous operational scenarios, cost inputs for comprehensive mitigation should the project remain in place, decommissioning cost estimates, and replacement power cost estimates from a range of publicly available wholesale price forecasts. The primary model outputs are cost comparisons of the relicensing and decommissioning cases across a range of mitigation cost estimates and a range of replacement power cost estimates. Current costs and conditions are estimated in the model to provide a basis for the relicensing and decommissioning cases. However, current design and operating conditions are not a future project alternative because the Klamath Hydro Project does not meet current environmental regulatory standards for water quality and fisheries protection.

KPAAM is not a cost-benefit model in that it does not attempt to quantify or monetize the social or natural resource costs and benefits associated with each alternative case. Rather, it examines the private costs that will be incurred by PacifiCorp and its ratepayers in order for the Klamath project to meet modern environmental regulatory standards; the Relicensing and Decommissioning scenarios are two potential options for meeting these standards.

The Energy Commission staff, Interior and their contractors had several design objectives for the KPAAM:

- Develop an analytic tool with appropriately rigorous standards that could be used by government and stakeholders in settlement negotiations, FERC relicensing, and Public Utility Commission proceedings in multiple Western States.
- Disclose and document all analytic assumptions, ranges of uncertainty, methods and data sources to provide transparency.
- Use electricity supply and cost forecasts from established public sources.

- Adopt the “ratepayer perspective” rather than the “societal perspective” in order to maintain a focused analysis on the costs of project alternatives, rather than general, societal level costs and benefits.[3]
- Develop a flexible analytic tool that allows other stakeholders and users to alter input assumptions for major variables in order to model additional scenarios and sensitivities.

KPAAM relies on input data developed to represent several questions that describe current conditions and alternative futures:

- How does the Klamath project operate today?
- If relicensed, how would it operate and what are the costs of environmental impact mitigation measures?
- If decommissioned, what are the removal costs, outstanding investments that would be “lost” and replacement power costs?
- Under decommissioning and relicensing, what are the effects on power production and what are the net replacement power costs?

Input data were developed cooperatively by the Energy Commission and Interior. The U.S. Bureau of Reclamation (Bureau) provided the hydrologic modeling results, whereas the information for mitigation cost estimates came from the Bureau, U.S. Bureau of Land Management, U.S. Fish and Wildlife Service, and information filed by PacifiCorp, the current owner of the Klamath Dam complex, in various State and Federal public forums. Initial cost estimates for decommissioning the four main Klamath dams come from the Bureau, based on an initial estimate from the California Coastal Conservancy. The Conservancy and their consultant are developing a more thorough decommissioning cost estimate. The economic part of the model was implemented by M.Cubed, a consultant to the Energy Commission.

Description of the Klamath River Hydroelectric and Irrigation Systems

The Klamath River is the second largest river by volume in California, flowing southwestward from the Cascade Mountains for approximately 350 miles through Oregon and California to its confluence with the Pacific Ocean in California. Primary uses of this river include domestic, agricultural, and industrial water supply; cold and warm water fisheries; and recreation.[4]

The Klamath Hydroelectric Project currently totals 169 MW nameplate capacity from four main power dams. The Northwest Power Planning Council (NWPPC) rates the Klamath Project as having 92 MW of firm winter capacity.[5] FERC rates the project’s

[3] Thus, environmental costs and benefits have not been explicitly included here, but that exclusion does not diminish the importance of those costs—it only acknowledges the difficulty of quantifying those costs and benefits.
[4] http://www.coastal.ca.gov/nps/Web/cca_pdf/ncoastpdf/CCA1KlamathRiver.pdf.
[5] As listed in “Res 121504 HYLoss.xls” at www.nwcouncil.org

dependable capacity at 42.7 MW.[6] Three small hydroelectric projects scheduled for removal from the FERC project total 5 MW, and are not discussed further. Average annual generation for the Klamath Project has been 676,016 megawatt-hours (MWh), or 676 gigawatt-hours (GWh), during the period from 1983 to 2003.[7] Due to a recent efficiency upgrade completed in 2005 that increased the nameplate capacity from 151 to 169 MW, current average annual generation is estimated to be 716.8 GWh.[8] Hydrology for the hydro project is highly regulated by the Bureau's irrigation project upriver from the J.C. Boyle powerhouse and reservoir, and by flow regimes required under the ESA for salmon protection. The Boyle facility is located on the Oregon portion of the Klamath River, with the remaining three large powerhouses located down-river in California.

Table 1-1: Nameplate Capacity of Four Main Klamath Powerhouses (MW)

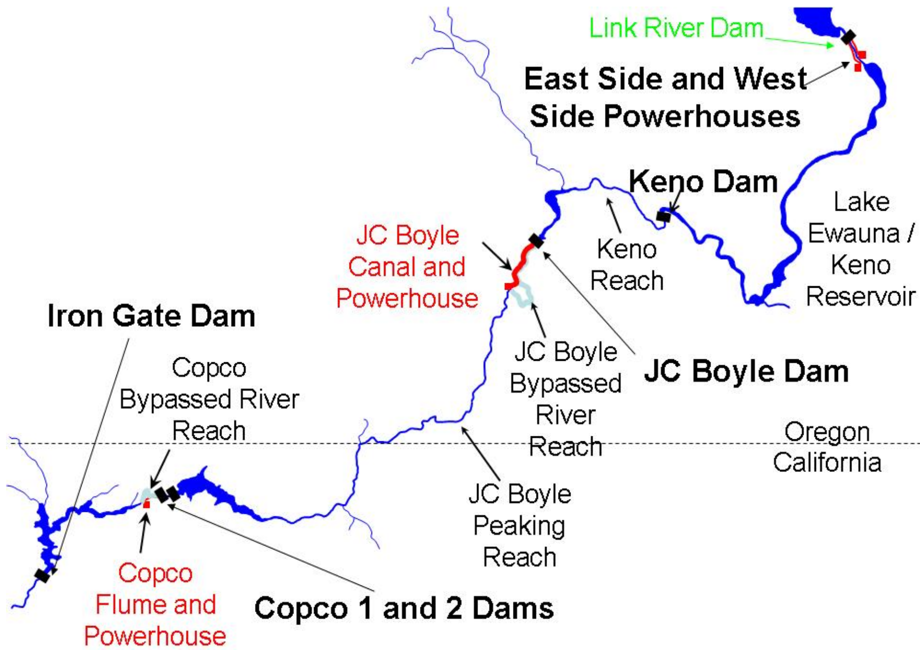
J.C.Boyle	97
Copco 1	20
Copco 2	27
Iron Gate	18

PacifiCorp developed the Klamath Project in two phases. The Copco facilities were constructed starting in 1908, while the Boyle and Iron Gate facilities were added in the late 1950's. The Boyle powerhouse is generally portrayed as a peaking facility, with Iron Gate as a regulating facility to allow for peaking dispatch of the up-river facilities. The Klamath Project has no large storage reservoir capacity available for seasonal dispatch, although the Boyle facility has a small reservoir that can store and release water in a peaking function on a daily basis. The peaking pulse flows are then captured by the three down-river powerhouses.

The Klamath Project is located below the Klamath Irrigation Project managed by the U.S. Bureau of Reclamation (See Figure 1-1). Upper Klamath Lake flows into the Klamath River, and is used to a certain extent for seasonal storage for both irrigation and power demands. Link River Dam retains Upper Klamath Lake. Keno Reservoir is below Upper Klamath Lake and is used for further storage. Keno Dam is owned and operated by PacifiCorp, but it does not generate power. Because the waters above Keno Dam are the responsibility of the Bureau, inflows to Keno Dam are controlled by the Bureau, but PacifiCorp manages releases from Keno to meet objectives required of the Bureau by various constraints, including environmental regulations and flow schedules for salmon populations protected by the federal Endangered Species Act (ESA). PacifiCorp then passes those flows through its system to be released from Iron Gate Dam at the bottom of FERC Project 2082.

[6] FERC Draft Environmental Impact Statement for the Klamath Hydroelectric Project No. 2082, Table 4-1, September, 2006. However, no definition of "dependable capacity" is provided.
[7] This value has not been adjusted for changes in facilities or regulations governing flows and operations during that period, so the annual values are not exactly comparable to each other. This average should be used only for order of magnitude comparison purposes.
[8] FERC DEIS at 1-1.

Figure 1-1: Location of Key Facilities for the Bureau of Reclamation Irrigation Project and the PacifiCorp Klamath Hydroelectric Project



PacifiCorp regularly describes the Klamath Hydro Project and Boyle powerhouse as peaking facilities in its documents filed with FERC for the project's relicensing proceeding.[9] However, due to the above-described constraints on project water in-flows and to the constraints on project dispatch in order to meet down-river environmental flows, the project is increasingly more characteristic of a run-of-river operation that generates power as flows are available. Following is an excerpt from a recent PacifiCorp filing to the California Public Utilities Commission in the utility's general rate case:

> "Limitations on PacifiCorp's operational flexibility have become increasingly severe in recent years. For example, current USBR Water Management Policy and Biological Opinion elevation targets for Upper Klamath Lake require a rapid refill of Upper Klamath Lake. … This rapid refill policy eliminates much of PacifiCorp's operating discretion, diminishing the ability to store and release water in Upper Klamath Lake for the benefit of hydro generation."[10]

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[9] PacifiCorp, *Final License Application to FERC for the Relicensing of the Klamath Hydroelectric Project, FERC 2082*, at H 5-2, February 2004.
[10] *Opening Brief of PacifiCorp in its General Rate Case Proceeding U-901-E before the California Public Utilities Commission*, Application 05-11-022, August 28, 2006 at p. 31.

Klamath River Fisheries and Natural Resources

The Klamath River watershed in Southern Oregon and Northern California encompasses about 12,000 square miles and flows about 350 miles from its headwaters to the Pacific Ocean. Major tributaries include the Williamson, Wood, and Sprague rivers in the upper watershed, and the Scott, Shasta, Salmon, and Trinity Rivers in the lower watershed. The watershed includes 96,000 acres of tribal trust lands, four million acres of private land and six million acres of public lands. The basin includes part of Crater Lake National Park, six National Wildlife Refuges and three Wild and Scenic reach designations as it flows through five National Forests. Four Native American Tribes hold land, fishing, hunting and subsistence gathering treaty rights in the basin, including the Hoopa, Karuk, Klamath and Yurok.[11]

The Klamath River Basin was once the third largest salmon-producing watershed on the West Coast, supporting large anadromous fish runs that included Chinook salmon, coho salmon, steelhead trout, sturgeon and lamprey, all of which supported significant commercial, tribal and recreational harvests. The upper basin lakes include two National Wildlife Refuges that provide migratory habitat for most of the waterfowl using the Pacific Flyway. Water from the Bureau's irrigation project supports numerous farming communities. Declines in populations for several of the fish species have resulted in both reductions in water deliveries and restrictions on commercial and tribal harvest levels – culminating in the 2006 restrictions on all commercial salmon fishing in order to protect Klamath River populations.

Historic records indicate substantial populations of Chinook salmon and steelhead trout used the upper basin above the Klamath Hydro Project for spawning. The summer-run Chinook population is now at remnant levels, while the fall-run has also diminished significantly. The steelhead trout population is also in steep decline. The coho salmon habitat is found primarily downriver from the Klamath hydropower project.

In 2002, an estimated 70,000 returning adult salmon were killed due to a disease outbreak caused by warm water temperatures and low summer flows. Large die-offs of migrating juvenile salmon have also been observed in recent years.

Flows from the Bureau's irrigation project from Upper Klamath Lake are regulated by two Biological Opinions from the U.S. Fish and Wildlife Service and NOAA Fisheries under the ESA. The "2012 BO Flows" used in the KPAAM are a water release schedule defined in the Biological Opinions.

In addition to the barriers to fish passage caused by the Klamath Hydro Project, other major contributing factors to fisheries declines in the basin include water withdrawals for irrigations, high water temperatures, and very poor water quality (nutrient loading

[11] U.S. Department of Interior, *Comments, Preliminary Recommendations, Terms and Conditions, and Prescriptions for Fishways*, filed with FERC for the Klamath Hydro Project Relicensing Proceeding, March 27, 2006. This filing provided the basis for this overview of Klamath River fisheries and natural resources.

and poor dissolved oxygen levels). Large summer blooms of toxic algae now occur regularly in the Klamath Hydro Project reservoirs. It is estimated that removal of the impediments to fish passage caused by the Klamath Hydro Project would create access to about 350 miles of historic mainstem and tributary habitats.

Relationship of the Klamath Project to the PacifiCorp System

Based on information from PacifiCorp's' 2004 Integrated Resource Plan (IRP) and its 2006 Update, PacifiCorp serves about 1.6 million customers across six Western states.[12] Total electricity sales in 2004 were 62,086 GWh. PacifiCorp's forecasted peak load for 2006 is 10,090 MW.[13] The company owns 8,419.5 MW of generating assets across four main energy types. Capacity and generation for 2004 are shown in Table 1-2:

Table 1-2: PacifiCorp Generating Capacity and Generation by Fuel Type - 2004

Fuel Type	No. of Plants	Nameplate Capacity (MW)	Percent of Total Capacity	Percent of Electricity Generation
Coal	11	6585.8	78.2%	68.4%
Natural Gas	5	723.8	8.5%	4.1%
Hydroelectric	54	1077.3	12.8%	5.4%
Wind	1	32.6	0.4%	0.2%
TOTAL	71	8,419.5	100.0%	78.1%

The additional electricity needed to meet PacifiCorp's customer load is procured through power purchase agreements with merchant generators and other utilities. For 2004, procurement totaled about 22 percent of PacifiCorp's system requirements.

PacifiCorp's hydro portfolio of 54 plants and 1,077.3 MW of nameplate capacity comprises 12.8 percent of PacifiCorp's owned generating capacity, and supplies 5.4 percent of total electricity. At the system level, the Klamath Hydro Project's 169 MW capacity and about 716.8 GWh[14] average annual generation comprises two percent of total capacity, and contributes about one percent to total electricity sales.

In PacifiCorp's recent update to its 2004 IRP, it describes plans to expand its generating capacity by 2,113 MW by 2014 in order to meet load growth.[15] The new capacity would include 1,636 MW of thermal resources (coal and natural gas), 300 MW of renewables (primarily wind) and 177 MW of demand side management. An additional 300 MW of capacity would become available via a transmission line

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[12] PacifiCorp, *2004 Integrated Resource Plan,* http://www.pacificorp.com/File/File47422.pdf, 2004.
[13] PacifiCorp, *2004 Integrated Resource Plan Update*, http://www.pacificorp.com/File/File57884.pdf, 2005. p. 32.
[14] This value varies depending on the historical record used and the assumptions about physical facilities and regulatory controls in place.
[15] PacifiCorp, *2004 Integrated Resource Plan Update*, p. 34.

upgrade, making a total of 2,413 MW in new resources available to meet load growth.[16]

In its 2003 *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, staff from the California Energy Commission concluded that decommissioning some or all of the Klamath facility was a feasible alternative that should be further examined during relicensing.[17] Given the size of the PacifiCorp system, the relatively large amount of capacity and energy already procured (i.e., 22 percent), and the amount of additional capacity and energy needed to meet projected load growth, the report also concluded that loss of the Klamath hydropower project "would not have a demonstrably significant effect on resource adequacy."

The Klamath Project is a small element of PacifiCorp's larger electric generation and transmission system. It does not provide capacity support needed for local reliability or voltage support. Klamath is not so large relative to PacifiCorp's system or so critical that a specific new resource in southern Oregon would be required for replacement. According to PacifiCorp's Final License Application to FERC, local transmission improvements totaling $5.6 million could allow replacement power to be brought in from the grid;[18] and the reduction of transmission congestion or replacement of transformers with more energy-efficient units may obviate the need for Klamath electricity at lower cost to the ratepayer.

PacifiCorp's energy planners are also assessing how to replace the energy and capacity from the Klamath Project. In a recent update to the Preferred Portfolio in its *2006 Integrated Resource Plan,* "Replace Klamath hydro units with alternative resources" is listed as Scenario Number 16 in its "Capacity Expansion Module Results." [19]

The Klamath Project is small compared to the both the total power needs of PacifiCorp's customers and relative to the scale of PacifiCorp's system-level need to add generation or reduce demand growth to meet load, reserve margins and transmission system reliability. Whatever decision PacifiCorp makes with its Klamath facilities, it plans on investing $2.3 billion for 2,413 MW of new generation,

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[16] *Ibid.*

[17] California Energy Commission Staff, *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, P700-03-007, Sacramento, California, May 2003.

[18] "If generation were to cease at the Klamath Project, PacifiCorp would still be able to service its local customers. Non-Project substations would remain available to supply power throughout the Project area.

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

(PacifiCorp. *Final License Application*, Exhibit H, Page 2-7, February 2004.)

[19] PacifiCorp, 2006 Update to Integrated Resource Plan, August 2006 Summary of Capacity Expansion Model Results.

transmission and demand side management by 2014.[20] Since Klamath makes a *di minimus* contribution to PacifiCorp's system, its importance to total regional energy supply does not appear to be significant. Loss of some or all of this energy would not significantly affect PacifiCorp's ability to provide electricity to its 1.6 million customers, nor would it materially affect rates.

The Use and Purpose of the Model

KPAAM provides a tool to assess the financial questions pertaining to relicensing and removal by comparing the alternatives in summary results that describe "least cost" options to meet environmental compliance and restoration goals, and "break even" or pivot points on potential net costs when relicensing is compared to decommissioning. These pivot points can be used to identify the situations where changes in relative costs between the two projects options can change decisions on the preferred option. Additional questions examined through modeling include:

- What are the key variables that drive model results?
- What are the uncertainty bounds?

To address uncertainty about key inputs, such as the cost of replacement power, "scenarios" describe sets of assumptions.[21]

In the end, one can compare results from different scenarios to see how outcomes overlap under different views of the world (which roughly describe different interests of parties to the proceeding).

Overview of Klamath Project Alternatives Analysis Model (KPAAM)

Chapter 2 of this report describes the hydrologic and power production CALSIM II modeling by the Bureau. Power production changes were cooperatively developed with the Bureau. Using the CALSIM II model, the Bureau estimated power production for current and hypothetical relicensing conditions. Data limitations prohibited the calculation of hourly generation, but there was representation of peak and off-peak differences.

[20] PacifiCorp, 2004 IRP Update.
[21] Two types of uncertainty, exogeneous and endogenous, are represented in the analysis:

Exogenous uncertainty due to natural (e.g., variability in annual rainfall, and societal processes, natural gas price variability) are quantifiable and thus represented in the model. For example, hydrology is represented using inferred probabilities from dry, average and wet rainfall years observed over the 44-year period from 1961 thru 2004.

Endogenous, "fork in the road" uncertainty (e.g., changes in regulatory or legal constructs) is not fully knowable or quantifiable. This uncertainty can be created by actors within the decision-making process, thus making "probability" estimates subject to influence by those who can change those probabilities. Applying a quantitative analysis, as is possible under exogenous uncertainty, is not an option for endogenous uncertainty. Instead, endogenous uncertainty bounds may be explored by creating composite sets of scenarios from possible values for uncertain inputs. Contrasting scenarios may show the range of plausible regulatory, legislative or broader social actions.

Chapter 3 describes KPAAM, which incorporates USBR data into an economic modeling construct. The KPAAM model has four primary cost categories:

- **Relicensing Mitigation Costs:** Cost estimates for relicensing mitigation measures and flow requirements were compiled and provided by Interior. Remaining investment in the facilities came from Form 1 filed by PacifiCorp with the Federal Energy Regulatory Commission.
- **Dam Removal Costs:** Dam removal costs were provided by the California Coastal Conservancy and their contractor, Gathard Engineering and Construction.
- **Remaining investment Costs:** Utilities raise private capital from shareholders to finance capital projects. The remaining, non-recovered investment costs due to shareholders if the Klamath project were to be decommissioned – also known as the ratebase book value – were taken from the 2004 FERC Form 1 filing.
- **Replacement Power Costs**: A unique feature of KPAAM is the inclusion of a set of six power price forecasts to capture the range of expectations about future replacement costs. This range is used to assess how uncertainty about future power costs can affect the economic benefits and costs derived from decommissioning versus relicensing. All of these price forecasts are derived from publicly-available sources.

Chapter 4 presents initial results in both tabular and graphical format. Appendix A contains a User's Manual for the model along with discussions on sensitivity analysis and recommendations for additional modifications to the study. Appendix B is a list of the line item detail of the mitigation measures included in the Relicensing Condition, including cost estimates and source information.

CHAPTER 2: HYDROLOGIC MODELING FOR KLAMATH HYDROPOWER RELICENSING ANALYSIS[22]

Introduction

The Technical Services center of the U.S. Bureau of Reclamation, U.S. Department of the Interior, developed a hydrologic model to simulate the potential for meeting system operating criteria for Current Conditions and Relicensed Conditions given a set of hydrologic inputs.

A base monthly model was developed using CALSIM II, a general purpose river and reservoir systems planning model developed by the State of California Department of Water Resources. The Klamath River locations represented in the model are Keno, J.C. Boyle, Copco Dams I and II, and Iron Gate Dam. A monthly model cannot explicitly represent such daily or hourly operational decisions as trade-offs among power generation, bypass reach flows, and ramp rates. Separate pre-processing analyses used available information to develop a monthly aggregate representation of these scenario elements for the range of potential flow conditions at power plant locations. This data was then used in an Excel spreadsheet-based model to represent generation patterns within a week, both for meeting daily power demands and for delivering flows for rafting requirements.

Historical gains and losses between the main locations were developed from available gage data and general river system information. These local gains and losses were combined with both historical flows at Keno and a potential 2012 flow scenario for Keno based on the recent NOAA Fisheries biological opinion to capture a given set that represent two sets of boundary flow conditions.

This chapter presents details of the monthly model, development of the input hydrology, representation of facilities operations, and the pre-processed flow-power and flow-revenue relationships.

Power Production Value

The focus of the hydrology model is to estimate the differences in power production value created by different operating regimes. In other words, what are the changes in economic value from changes in the quantities and timing of power generation from the Klamath Project? This is *not* the same as a change in power generation. For example, it is possible to generate less energy, but if that smaller quantity is shifted to higher-value peak-load periods, then the total economic value can increase.

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[22] Primary technical contributions by Nancy Parker, U.S. Bureau of Reclamation, Technical Services Center, and Richard McCann, M.Cubed

Power production value is computed from the same wholesale market price forecast for the year 2006 for all power plants in the Klamath River system. These prices represent the relative value of power that PacifiCorp would have to procure or generate from other power plants if the Klamath Project was not operating at the hourly levels found in this analysis. The 2006 hourly price profile represents the relative values of peak and off-peak generation. These relative values are then scaled up to annual power price forecast values in the economic analysis discussed further in Chapter 3. It is important to note that the hourly price forecast used in this step of the model does not have a direct relationship with the annual price forecasts used later in the economic analysis. However, it is assumed that the relative values between hours will remain similar in the future.

The average weekday peak price is 33 percent higher than the off-peak average price. Weekday peak, weekend peak, and weekly off-peak prices are defined in dollars per MWh. However, the absolute values are not important for this step of the analysis, only the relative values between peak and off-peak periods. Table 2-1 below shows these values. Peak prices for system-wide high load periods are applicable 12 hours per day, defined as 6 AM to 6 PM, in June through August, and 14 hours per day, 6 AM to 8 PM, in other months, seven days per week. These prices are in effect whether the power plant is actually generating in peak periods or not. Off-peak prices for low load periods are in effect for the balance of each day. Weekend peak prices are applicable on Saturdays and Sundays. Peak load hours represent 58.3 percent of the year.

Table 2-1: Forecasted Monthly Wholesale Power Prices by Month and Load Period for 2006[23] (2005$/MWh)

	Peak	**Off Peak**	**Weekend**
January	37.73	31.82	33.69
February	36.45	30.52	33.37
March	35.42	32.93	35.05
April	34.72	28.17	30.70
May	33.13	25.12	27.60
June	37.43	26.13	27.81
July	41.19	28.77	33.20
August	67.83	29.79	35.75
September	38.00	29.66	34.78
October	38.47	30.67	33.88
November	40.05	34.10	36.79
December	39.41	34.16	37.21

Input Hydrology

Input hydrology to the Klamath Hydro Project is subject to U.S. Bureau of Reclamation decisions and regulatory requirements on the Klamath Irrigation Project.

[23] Source: Northwest Power Planning Council Staff, "Aout R5B9 Final 062804HR 2006.mdb," prepared for the *Fifth Power Plan*, Portland, Oregon, 2003.

Inflows are a constraint that affects power generation in the Klamath Project, so two inflow regimes were modeled:

1. “Historic”, which represents actual flows prior to 2005; and
2. “2012 BO”, which represents the flow objectives for 2012 specified in the recent NOAA Fisheries Biological Opinion. A recent court decision could accelerate the implementation of these latter objectives.

Input hydrology – inflows, gains, and losses – was developed for the 44-year period of record comprising water years 1961–2004. The specific segments, nodes, inputs and assumptions are listed below. Figure 2-1 shows the inputs and assumptions graphically.

Inflow at Keno is the upstream end of the relicensing model. Two traces of Keno inflow were used in this study. Historical flow is the USGS gage record for Klamath River at Keno. “2012 Flow” is the Keno flow that would result from Klamath Irrigation Project operations that meets long term Iron Gate flow requirements proposed by NOAA Fisheries.

Iron Gate Dam flow is at the downstream end of the relicensing model. Flows at this location are targeted to be the historical flows or the 2012 flows associated with the proposed NOAA requirements described above.   The focus of the model runs is to define power plant and other release operations between Keno and Iron Gate for a given set of flow conditions at the two locations.

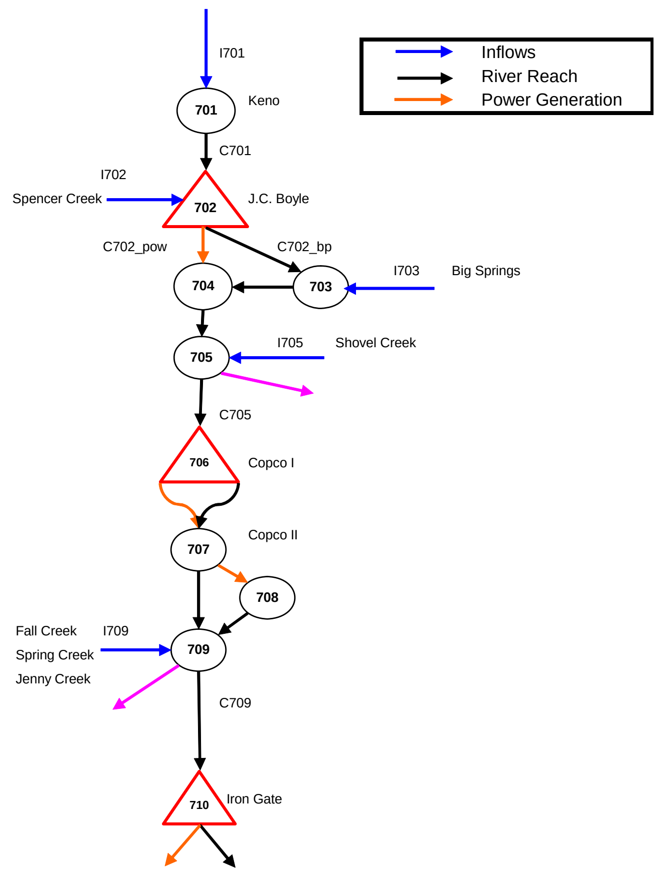
Accretions (i.e., the cumulative flows collected along the stream course) were developed for each reach of the model based on USGS gage data and other information.

Keno to J.C.Boyle – USGS gage records for the J.C. Boyle gage are missing for 1972-1974, 1980-1982, and 1988. Regression equations were developed to compute Boyle flows from Keno flows on a monthly basis. Correlation measures for these relationships were very good with all values above 0.9 except for July (0.88) and August (0.83). A portion of the Keno to Boyle gain is due to the large natural spring flow into the J.C. Boyle Bypass Reach. This flow has been estimated as a constant 220 cubic feet per second (cfs), adjusted as necessary to align with available historical daily data. Gains for the reach were divided into two parts – local inflow into J.C. Boyle reservoir above the dam, and spring flow into the bypass reach. Total gain was computed as the difference between J.C. Boyle flow and Keno flow. The spring portion of the total gain was computed as the minimum of (220 cfs or the gain in the Keno to Boyle stretch). The Spencer Creek/side inflow portion of the gain was computed as the maximum of (0 cfs or the gain in the Keno to Boyle stretch minus 220 cfs).

J.C. Boyle to Copco I and II – It is assumed that there are no accretions between the two Copco facilities. Shovel Creek and other side inflows do flow into Copco Reservoir and contribute to the water supply available for power generation. There is a USGS flow record below Iron Gate but not below the Copco facilities. A method was needed to separate the total J.C. Boyle-to-Iron Gate flow differences into above Copco and below Copco. Hourly data from a PacifiCorp modeling study provided a 2000 to 2004 perspective on the percentage of Boyle to Iron Gate gains that occurred upstream of Copco dam. Based on this information, the gain/loss between J.C. Boyle and Copco Dam was computed as 10 percent of the J.C. Boyle to Iron Gate flow difference.

Copco to Iron Gate – This reach includes inflows from Fall Creek, Jenny Creek, Spring Creek (not explicitly modeled) and other side inflows. The gain/loss between Copco and Iron Gate was computed as 90 percent of the J.C. Boyle to Iron Gate flow difference.

Figure 2-1: Schematic Representation of the Klamath Project Hydrology



Water Year Types – Hydrology was drawn from the 44-year trace used by the USBR in modeling and managing the Klamath Project. The USBR has classified the hydrologic conditions for each year as shown in Table 2-2.

Table 2-2: Hydrology Based on Net Inflow to Upper Klamath Lake from 1961 thru 2004

Hydrologic Conditions	Years	Probability
Dry	6	13.6%
Below Average	12	27.3%
Average	12	27.3%
Above Average	9	20.5%
Wet	5	11.4%
Total Years	44	

Overall, accretions contribute an average of 10 to 20 percent to Iron Gate flows and 13 to 37 percent to J.C. Boyle flows. Accretion distributions have distinct characteristics in the two reaches. As shown in Figures 2-2 and 2-3, the exceedence plot of gains in the reach below Keno is quite flat in the middle, reflecting the dominant influence of the Big Springs. It follows that accretions are a greater percentage of the J.C. Boyle flow in summer, when upstream inflow decreases while the Springs continue to flow. The J.C. Boyle to Iron Gate reach accretions plot reflects a more seasonal hydrology, and the percentage contribution to Iron Gate flows is typically higher in the spring months.

Figure 2-2: Accretion Exceedence – Keno to JC Boyle

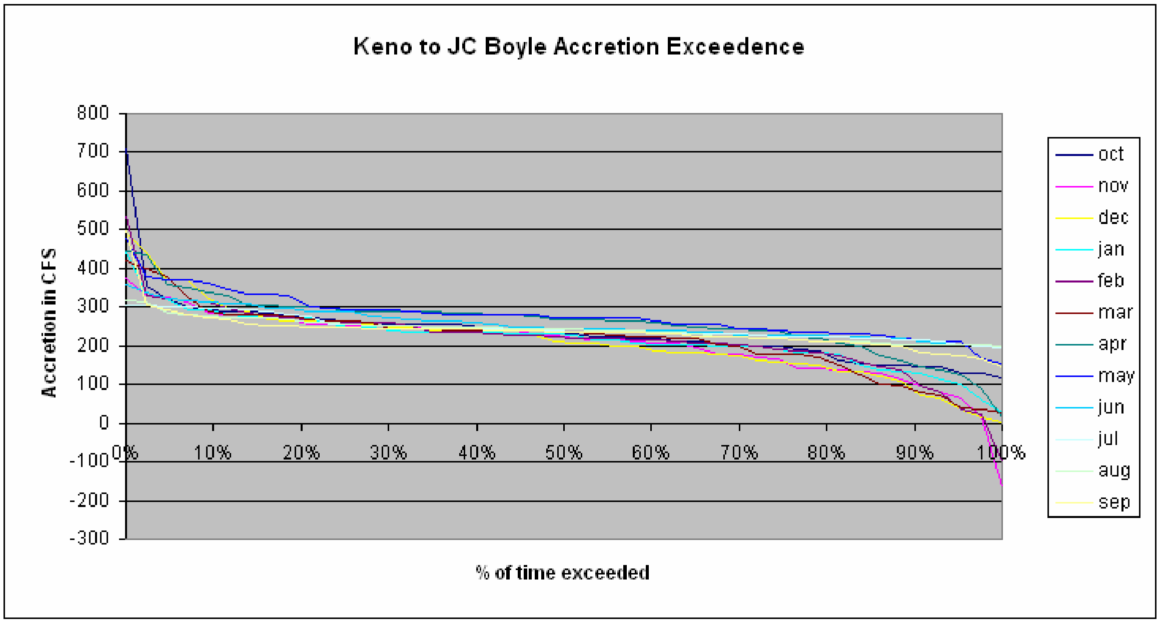
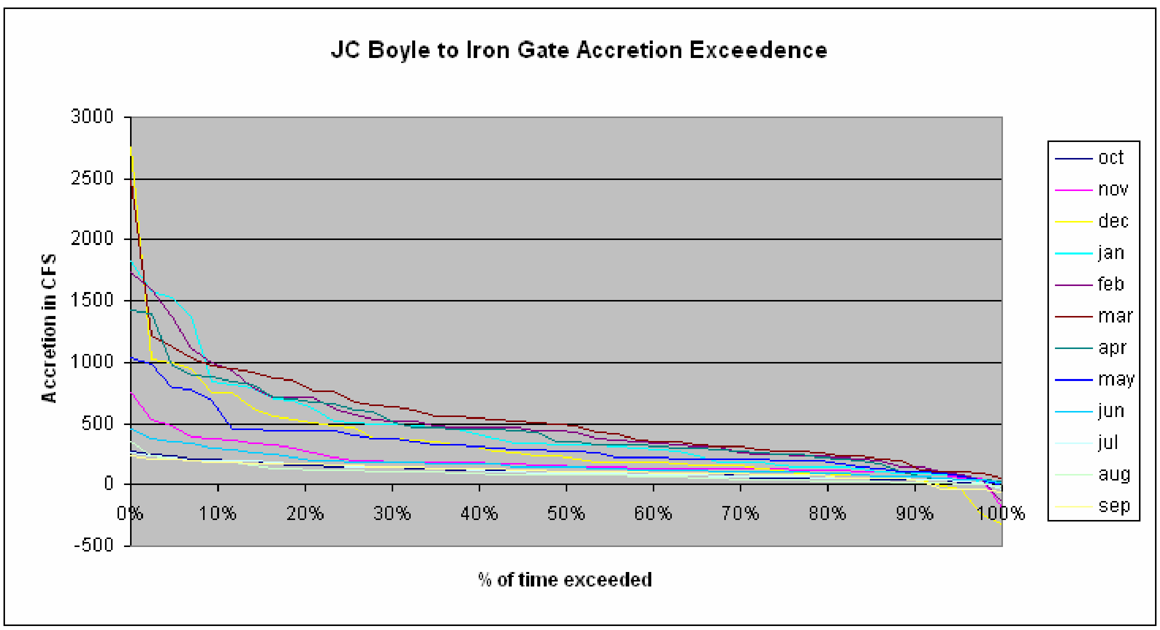


Figure 2-3: Accretion Exceedence – JC Boyle to Iron Gate



Klamath Project Operational Rules

The second set of constraints on project operations are specified in the FERC Project 2082 license conditions. The "Current" conditions represent operational constraints under the current license. The "Relicensed" conditions are operations that would be mandated under Section 4(e) of the Federal Power Act if the project were relicensed.[24] Operational rules at the J.C. Boyle, Copco I, Copco II, Fall Creek and Iron Gate facilities were developed for the Current Conditions and Relicensing cases.[25] These rules encompass power plant capacities, peaking targets, ramp rate restrictions, bypass reach release targets, and active capacity.

Combining operating conditions with the two independent inflow constraints, the following three overall hydrologic cases were defined and used for analysis:

1. Current license conditions with Historic Keno Flows and the J.C. Boyle upgrade that added 10 MW;
2. Current license conditions with 2012 Biological Opinion Keno Flows and the J.C. Boyle upgrade; and
3. Preliminary Section 4(e) mandatory license conditions by BLM with 2012 Biological Opinion Keno Flows and the J.C. Boyle upgrade.

The third scenario above is the base case used for the economic analysis that compares relicensing with decommissioning described in the next chapter of this report. The first two scenarios represent what might be generated without the relicensing conditions. In particular, the second case is used to represent the amount of generation available to PacifiCorp in the interim period before decommissioning, from 2008 to 2013 under the assumption that interim relicensing conditions would not be as restrictive as those under a permanent license.

Choices and Uses of Time Steps for Modeling

Because a monthly timestep model does not explicitly represent daily or hourly operational decisions such as trade-offs among power generation, bypass reach flows, and ramp rates, separate pre-processing analyses used available information to develop a monthly aggregate representation of these scenario elements for the range of potential flow conditions at each power plant location.

These pre-processors calculated daily or weekly power generation and its associated economic value using heuristic rules given the various specified physical constraints. Where more than one power production operation was possible, the one which

[24] We include only the conditions that directly affect flow and release decisions at J.C. Boyle Dam, based on the preliminary 4(e) conditions of the BLM. Additional constraints were recommended by fish and wildlife agencies, but were not modeled.
[25] A scenario that used Current License Conditions with Historic Keno Flows was created solely for calibration purposes. This scenario was compared to actual historic generation and found to be within 8% of actual historic data, indicating that the model had sufficient accuracy for the analytic purposes here. This is discussed further below.

resulted in the greater economic value was selected. Note that this is not necessarily equivalent to maximizing total power generation.

How this modeling structure was implemented for each plant in the project is discussed below.

John C. Boyle Power Plant

J.C. Boyle Power Plant is currently operated as a "peaking" facility, albeit limited – water is stored in J.C. Boyle Reservoir at night and drawdown occurs during daylight hours. Summer (June to August) peaks target a high flow duration of four hours, while for the rest of the year the high flow duration is targeted at 10 hours. However, a significant flow is released throughout all hours due to storage conditions and license conditions.

Unit 1 has a capacity of 1250 cfs with a generating capacity of 50.35 MW. [26] Unit 2 has a capacity of 1600 cfs with a generating capacity of 47.6 MW. Minimum flow for power production is 344 cfs (8 MW) for Unit1, and 407 cfs (10.2 MW) for Unit 2. These properties were used to construct a lookup table to determine power generation as a function of turbine flows. The storage pool available for peaking operations is assumed to be 1780 acre-feet. Release requirements for the bypass reach and ramp rate restrictions vary by scenario and are described in Table 2-3 below.

Table 2-3: J.C. Boyle Operating Scenarios

Scenario	Ramp Rate	Bypass Flow Requirement
Current Condition	9 inches/hour	100 cfs
Relicensed Condition: BLM Flow Condition – Year Round	2 inches/hour	min(inflow, max(470 cfs, 0.4*inflow))
Relicensed Condition: BLM Summer Condition	2 inches/hour	May-Oct: peaking reach release of 1550-3000 cfs once per week to meet on-river recreational demand
Relicensed Condition: BLM Flush Flows	300 cfs/day, 2 in/hr down, 6 in/hr up	full inflow for 7 days between Feb 1 and April 15 when/if inflow first exceeds 3300 cfs

The Relicensed Condition is based on the preliminary Section 4(e) conditions of the Bureau of Land Management, U.S. Department of the Interior. In addition to the

[26] PacifiCorp, *Klamath Hydroelectric Project, FERC No. 2082 J.C. Boyle Development Units No. 1 and No. 2 Turbine and Generator Nameplate Changes*, Letter to Magalie Roman Salas, Secretary, Federal Energy Regulatory Commission, October 20, 2006.

reduced ramp rates and increased base flows described in Table 2-3, the Relicensed Condition would allow only a weekly peak operation from May to October, entailing a peaking reach release of 1500 to 3000 cfs at a maximum of once a week to meet weekend recreational demand such as whitewater rafting, rather than the daily peaking operations in the Summer of the Current Condition. This operation restricts ramp rates to two inches/hour.

The power generation pre-processor for J.C. Boyle was built in an Excel spreadsheet to represent the possible peaking operation for a given combination of ramp rate, peak period target, and bypass flow requirement. Two versions of the model were used – a 24-hour model to compute daily peaking operations, and a seven-day model to describe the weekly peaking May-October Relicensed Condition flow operation. The daily and weekly peaking traces were developed for a range of inflow rates. These traces were then used to compute the power produced and the associated value. This process enabled the generation of lookup tables that represent a piecewise linearization of power generation and value as a function of reservoir inflow. Separate tables were developed for specific combinations of ramp rates and bypass flow requirements.

Copco I and II

The Copco Power Plants have historically followed the peaking pattern of J.C. Boyle Power Plant, and it is assumed that a daily peak operation will continue to be the focus of these facilities under both Current Conditions and the Relicensing scenarios. This assumption implies that Copco Reservoir will absorb the impact of the weekly peak operation at J.C. Boyle for the Relicensed Condition.

Copco I has two units with a combined hydraulic capacity of 3200 cfs and a combined generation capacity of 20 MW. Minimum flow for power production is 258 cfs (0.33 MW) for Unit 1, and 305 cfs (1.5 MW) for Unit 2. Copco II has two units with a combined hydraulic capacity of 3200 cfs and a combined generation capacity of 27 MW. Minimum flow for power production is 241 cfs (1 MW) for Unit 1 and 467 (3.8 MW) for Unit 2. These properties were used to construct lookup tables that define power generation as a function of total turbine flow.

Peaking traces were developed for the two Copco facilities to roughly follow the shape of the J.C. Boyle peaking traces under Current Conditions. This is a conservative assumption, given that the Copco power plants do not have ramp rate restrictions. Separate lookup tables were developed to define power generation and value as a function of inflows for each facility. Copco I has no bypass reach, and Copco II requires 10 cfs to go through its bypass reach.

The Relicensed Condition includes status quo operational requirements at Copco II dam, including a 10 cfs minimum flow in the bypassed river reach below the dam. FERC and state and federal agencies have recommended increased bypass flows to the river and reduced diversions to the Copco II powerhouse to benefit fish in the bypassed river reach. FERC's Staff Alternative includes a 70 cfs minimum flow, while state and federal fish and wildlife agencies recommend a 730 cfs minimum flow. If adopted by FERC, the increased minimum flow requirements could further reduce power production at the Copco powerhouses in the Relicensed Condition.

Fall Creek Power Plant

Fall Creek Power Plant is a run-of-river facility consisting of three turbines with a combined maximum capacity of 50 cfs generating a total of 2.2 MW. Power production is assumed to be linear with river flow. No power is assumed to be generated for river flows below five cfs, which is typically the bypass flow. Historically, the facility has shown an annual plant factor of 62 percent, and overall power and revenue computations are multiplied by 0.62 to reflect this. Power revenue is computed as a function of the hourly power production rate and hourly prices for weekday peak hours, weekend peak hours, and off-peak hours. This representation of the Fall Creek facility is the same for the Current Conditions and Relicensing scenarios.

Iron Gate Power Plant

Power production values for Iron Gate Power Plant are computed for a constant flow rate through the facility for each month. Although Iron Gate Dam impounds storage that could be used for peaking operations, the ESA flow requirement in the river below the dam precludes this type of operation. Iron Gate Power Plant has a capacity of 1735 cfs which can generate 18 MW. Based on 2001-2005 daily data from PacifiCorp for power generation and turbine flow, a regression equation was constructed to calculate daily power produced as a function of flow:

$$Power = 0.2899 * Flow - 51.915 \quad (R^2 = 0.9761)$$

Historically, the facility has shown an annual plant factor of 73 percent, which is used to scale overall power and value from this facility. Power value is computed as a function of the daily power production rate and hourly prices for weekday peak hours, weekend peak hours, and off-peak hours. This representation of the Iron Gate facility is the same for the Current Conditions and Relicensing scenarios.

Hydrologic Model Results

Table 2-4 summarizes the generation output from the Klamath Project for each of the modeled cases. The historic average for the 1982 to 2003 period drawn from Energy Information Administration data is 676,015 MWh. The model result averaged for the same conditions over a longer period from 1961 to 2004 is 621,460 MWh, which is 92 percent of the historic average. The difference between historic and modeled generation reflects the use of assumptions about current conditions that are less precise than actual operations, and changes in operating objectives and constraints over the years, which are assumed to be constant in the model over the 44-year period. In other words, we cannot expect the model to reproduce historic results because the model uses a static set of conditions from a point in time, i.e., 2004, while the actual system experienced changes over the years in both infrastructure and operating procedures. Due to these data limitations, achieving a calibration standard within 8 percent is a reasonable standard.

Table 2-4: Power Generation Cases – Changes in Average Annual MWh over 44 Hydrological Years

Cases	**MWh**	**Change**
Historic Average 1982-2003 (EIA Data)	676,015	
Modeling Results for Modeled Power Generation Cases		
Current License Conditions with Historic Keno Flows (for calibration)	621,460	
Current License Conditions with Historic Keno Flows & J.C. Boyle Upgrade	703,432	13%
Current License Conditions with 2012 BO Keno Flows & J.C. Boyle Upgrade	727,926	3%
Relicensed Conditions w/ 2012 BO Flows & J.C. Boyle Upgrade	562,790	-23%

The additional 10 MW in capacity from the J.C. Boyle upgrade in December 2005 adds 13 percent to expected annual generation.[27] Using the flow objectives for 2012 in the NOAA Fisheries Biological Opinion (2012 BO) adds another 3 percent to the expected generation, totaling 727,926 MWh on an annual average basis. (The 2012 BO requires more downstream releases from Keno, which means that more water is available in the system to go through the generating turbines.) This level of electricity generation represents current operating conditions and the appropriate baseline against which future condition generating reductions are measured. This is also the amount of generation that would be lost if the plants were decommissioned.

The preliminary mandatory relicensing conditions for increased instream flows and reduced ramping rates proposed by the environmental regulatory agencies then decrease expected average generation by 23 percent from the baseline to 562,790 MWh.

Note that if the higher bypass flows for the Copco powerhouses are adopted in a new FERC license, project generation would be further reduced.

These modeled changes in the amount and timing of electricity generation from the environmental mitigation measures are carried forward to the economic comparison of the relicensing and decommissioning cases. It is also likely that some additional

[27] This upgrade involved replacement of a turbine runner and generator stator coil. Note that PacifiCorp apparently miscalculated the total nameplate capacity in the Project in this filing (PacifiCorp claimed 179MW, rather than 169MW). (PacifiCorp, *Klamath Hydroelectric Project, FERC No. 2082 J.C. Boyle Development Units No. 1 and No. 2 Turbine and Generator Nameplate Changes*, Letter to Magalie Roman Salas, Secretary, Federal Energy Regulatory Commission, October 20, 2006.)

constraints that were not modeled will be imposed in any new license based on the recommendations of fish and wildlife agencies at other Project facilities.

In addition, the model estimated the amount of generation segmented into peak and off peak hours. The results are summarized in Table 2-5. Based on historic conditions, about 70 percent of total generation occurs in the 58 percent of the hours defined as “peak load.” The remainder is generated in off peak hours due to high flows, particularly during the winter, that cannot be stored overnight or across seasons to be released during peak hours, or regulatory requirements to meet downstream flow objectives. The changes proposed for relicensing would have a minimal impact on the ability to generate during peak load hours according to the model runs. The 23 percent reduction in generation is evenly spread across all periods.

Table 2-5: Peak Generation by Case - Average Annual MWh over 44 Hydrological Years

Case	**Peak MWh**	**% Peak of Total**
Current License Conditions with Historic Keno Flows (for calibration)	506,692	70.6%
Current License Conditions with 2012 BO Keno Flows & J.C. Boyle Upgrade	527,437	71.5%
Preliminary Mandatory Relicensed Conditions w/ 2012 BO Flows & J.C. Boyle Upgrade	401,879	70.2%

Even before relicensing, changes in river management over the last two decades have reduced PacifiCorp’s generation flexibility. At least 60 percent of Klamath’s output appears to be base load run-of-river generation whose amount and availability is not subject to control by PacifiCorp.

CHAPTER 3: ECONOMIC MODELING METHODS[28]

This chapter describes the economic portion of the model that was prepared by M.Cubed in consultation with analysts from the Department of Interior and Energy Commission staff. An Excel spreadsheet model is used to compare economic and financial costs of Klamath Dam relicensing and decommissioning using a variety of assumptions about the magnitude and timing of four cost categories. This model is called the Klamath Project Alternatives Analysis Model (KPAAM).

All results are presented in constant 2005 dollars (2005$), and many of the nominal values in the model are adjusted using the GDP Implicit Price Deflator.[29] A schedule of costs and revenues is developed for each category and then discounted to reflect when each action is taken and the applicable time horizon to estimate a net present value.[30] Modeling input data and assumptions are provided by state and federal agencies, as well as PacifiCorp filings with the Oregon and California Public Utilities Commissions and the California Energy Commission.

The summary results presented here are based on only one set of assumptions—certain changes in those assumptions could change the results. However, the range of assumptions used in this case should capture a broad array of possible outcomes. These outcomes are not weighted for likelihood of occurrence. In most cases, no probabilities can be assigned to the differences in assumptions - such as differences in future electricity prices. The results can be used though to assess the potential bounds on future outcomes. The KPAAM model is structured so that it can easily accommodate changes in those assumptions to assess the sensitivity of the results. (This function is discussed further within the User's Guide in the appendix.)

Scenario Summaries

The KPAAM model can create "scenarios" that are composites of values chosen for influential parameters, such as the starting and ending years of the study period and the discount rate for calculating net present values. The model is structured so that assumptions pertaining to decommissioning timing and order, replacement power costs, and mitigation measures, costs and timings can be adjusted. Economic and financial assumptions include: forecasts for inflation and real discount rates throughout the study period; and the financing terms (e.g., period for repayment) for infrastructure investments, decommissioning and mitigation measure costs; and the property tax rate. Table 3-1 shows the model parameter values used in this portion of the analysis. Results are presented in Chapter 4.

[28] Primary technical contributions by Richard McCann, Ph.D and James D. Fine Ph.D, M.Cubed.

[29] See the GDP Deflator tab in the model.

[30] Discount rates used for net present value calculations are shown in Table 4: User Selected Scenario Parameters. The Weighted Average Cost of Capital is assumed to be 9.08% and the inflation rate is set at 2.8%, yielding a real discount rate of 6.27%.

A study period of 30 years is used in KPAAM, which is typical of the time periods usually analyzed in the FERC licensing context, and is a fair representation of the design life for thermal generation resources such as coal and natural gas. It is shorter though than the 50-year license period that is typically sought by utilities and sometimes granted by FERC. How this value affects the results can be assessed through subsequent sensitivity analyses in KPAAM.

The discount rate of 9.08 percent is derived from PacifiCorp's weighted average cost of capital (WACC) as filed with the Oregon Public Utilities Commission.[31] The WACC is typically used to discount utility investment costs and represents the investment cost to be recovered over time from ratepayers. Other discount rates are not appropriate unless they can be shown to flow through directly to consumers. The inflation rate of 2.8 percent was derived from the difference in the U.S. Treasury 30-year bonds and inflation-adjusted bonds.[32]

Decommissioning and mitigation costs have two treatments for uncertainty. The first is through an explicit uncertainty adjustment factor which calculates the low and high ends of cost range estimates. This uncertainty factor is set at 30 percent for both decommissioning and mitigation costs, [33] and captures the uncertainty in the engineering cost estimates. It is assumed that these uncertainties for decommissioning and mitigation are correlated. In other words, if the cost estimates for decommissioning are low, then it is probably true that the estimates for mitigation costs, such as the construction of fish ladders, are also low. This assumption is based on the inherent similarities in the physical setting, and in the methods used in developing the cost estimates. The second uncertainty is in the timing sequence for when the mitigation measures are adopted and implemented. This report does not assess the effect of this temporal dimension of uncertainty, but the KPAAM model is structured so that this type of analysis can be developed quickly and easily.
Additional important assumptions pertain to the estimates of replacement power costs. There is a placeholder for a non-firm power discount, but it is currently set at 0 percent (i.e., no adjustment). Another price adjustment represents the change in the daily timing of power production to represent the percent of peak power generated relative to historic and current conditions. The current condition value is set at 101 percent, meaning that the value of peak power is one percent more in the current (BO 2012) conditions compared with historic operations. The relicensing peak power value is derived at 97 percent of current conditions, implying that the mitigation measures reduce peak value by four percent. This change occurs because generation shifts slightly from peak load to off-peak periods as a result of changes in instream flow releases and ramping rates. Table 2-5 shows that the peak generation share decreased by 1.8 percent. This implies that the lost peak power was about twice as valuable as the off-peak generation that replaced it.

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[31] PacifiCorp, Oregon Public Utilities Commission Docket UE-179, November 2005.
[32] U.S. Department of the Treasury, http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/ltcompositeindex.shtml, and http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/yield.html, June 28, 2006.
[33] In the model, the cost estimate multiplier may also be adjusted to raise or lower the midline estimate from which high and low range values are calculated.

Table 3-1: Scenario Parameters Used for Study

Start Year	2008
Study Period (Years)	30
Ending Year	2038
Financing	
Weighted Average Cost of Capital (WACC) (%)	9.08%
Inflation Rate (%)	2.8%
Real Discount Rate (%)	6.27%
License Term = Finance Term for Infrastructure	30
Property Tax Rate	1.3%
Finance Term for Decommissioning	30
Finance Term for Mitigations	30
Replacement Power Costs	
Nonfirm Power Discount	0%
Power Price Premium from Peaking: Current conditions	101%
Power Price Premium from Peaking: Relicensed conditions	97%
Mitigation	
Uncertainty Adjustment	30%

Methods by Cost Category

1. Mitigation

A new FERC license for the Klamath project will likely include substantial requirements for mitigation of environmental impacts over the term of the new license period. However, until FERC issues the new license it is not possible to identify and model the exact terms that would be included. For the purposes of this analysis, a Relicensed Condition was developed that consists of 160 mitigation measures. This list includes all of the proposed actions in PacifiCorp's license application, most of the preliminary mandatory conditions from federal agencies, some mandatory measures that could result from state water quality certification, and some of the recommended measures from state and federal fish and wildlife agencies. A conservative approach has been used in determining which conditions to analyze.
Following is an overview of the mitigation costs analyzed in KPAAM. A complete list is included in Appendix B, including timing and costs for capital, operations and management.

- **Fish Passage Conditions** for full volitional upstream and downstream passage past four power dams (fish ladders), spillway and tailrace improvements, and hatchery operations.
- **Non-fish Passage Conditions** such as gravel augmentation, riparian restoration, terrestrial resource protection, recreational enhancements, and cultural resource protection.

- **Water Quality Conditions** to comply with water quality standards per section 401(e) of the Clean Water Act, including installation of oxygen diffusers at Iron Gate, and temperature control devices at Iron Gate and Copco 2. Since water quality measures to meet Section 401 of the Clean Water Act have not yet been prepared by the California and Oregon water quality agencies these estimates are proxies.

Summary results for the Relicensed Condition mitigation cost estimates for a 30-year period are provided in Table 3-2 and Figure 3-1. Total net present value of the mitigation costs range from $230 to $470 million, with a midline estimate of $360 million. The low and high estimates represent the 30 percent uncertainty factor added to each end of the midline case.

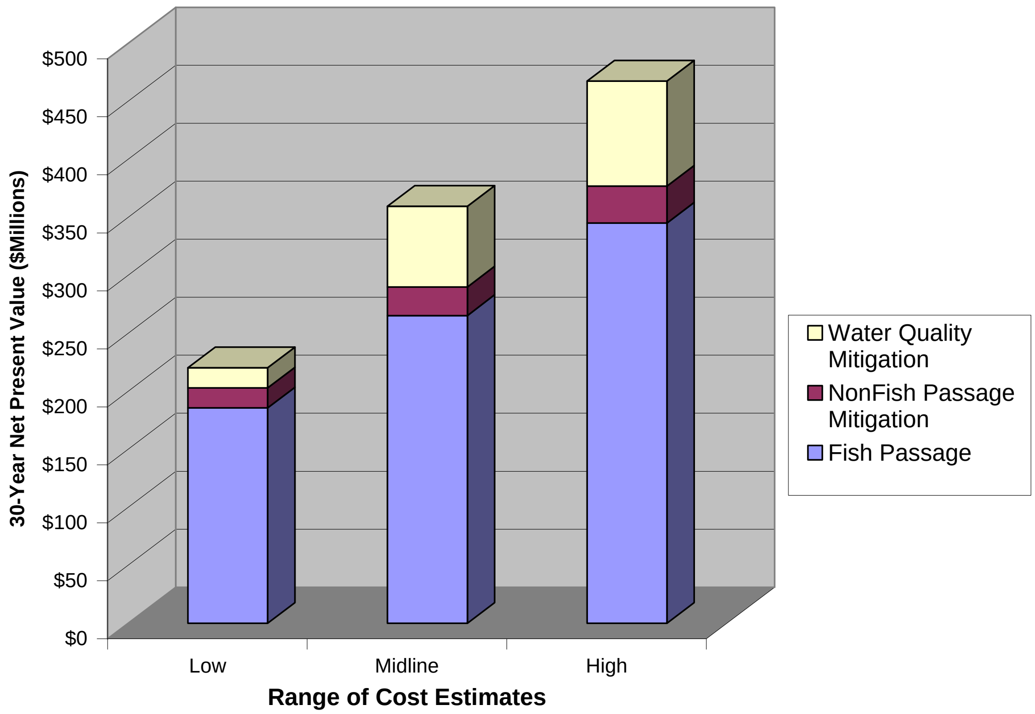
Table 3-2: Net Present Values of Relicensing Mitigation Costs (Millions of 2005 Dollars)

	Low	**Midline**	**High**
Fish Passage Conditions	$170	$250	$320
Nonfish Passage Conditions	$70	$90	$120
Water Quality Conditions	$20	$70	$90
Total Mitigation Costs	**$230**	**$360**	**$470**

Based on the assumptions used for this analysis, PacifiCorp's per-MWh production costs for the Klamath Project will increase substantially from an estimated $19 per MWh (current operating costs of $6 per MWh and the recovery of remaining investment costs of $13 per MWh). Increases in production costs from the mitigation measures could range from $30 to $61 per MWh, with the midline estimate at $47 per MWh. Total post-relicensing production costs for Klamath could range from $49 per MWh to $80 per MWh, with a midline cost of $66 per MWh. In comparison, ongoing production costs at many other hydro projects range from less than $10 per MWh up to $35 per MWh.[34] The added costs required to install and maintain the mitigation measures represent a financial threshold for comparison to the replacement power costs discussed later in this report.

[34] California Energy Commission, *California Hydropower System: Energy and Environment* Appendix D to the *Environmental Performance Report* and *2003 Integrated Energy Policy Report,* October 2003, Report No. 100-03-018.

Figure 3-1: Comparative Range of Mitigation Measure Costs for the Low, Midline and High Cases



The cost estimates are midline estimates for the Relicensed Condition, but substantial uncertainty exists around these costs. Estimates for more conventional capital cost for measures such as fish passage structures probably are more robust than for other measures for which measures have not yet been clearly identified, such as for water quality improvement. The model includes an uncertainty factor to capture a potential range for these costs. From the composite case and with little additional information about the uncertainties associated with individual estimates, a simple high-low range using +/- 30 percent uncertainty factor was derived from a range prepared for fish passage structures and is added to the midline cost estimates.[35] This factor can be further adjusted within KPAAM to assess the sensitivity of the results to this assumption. It also applies to the costs in total, so that it can be calibrated to capture an “average” of the uncertainties across measures.

Based on these midline estimates, PacifiCorp’s proposed mitigations total $40 million net present value over the 30-year term of the new license. Measures considered “mandatory” are estimated at $260 million, whereas measures considered “recommended” by the various agencies total $59 million.

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[35] In creating these high-low scenarios, no statement of probability is made as it has not been examined systematically. Analytical analysis of uncertainty is not tractable due to algorithm complexity, but Monte Carlo or other “brute force” methods may be used for assessment of the probability of outcomes. Users may adjust the uncertainty factor in the Scenario Summary tab.

The sources and assumptions that went into development of the Relicensed Condition are further discussed below. Complete documentation is included in Appendix B.

PacifiCorp's Proposed Mitigation: These measures were compiled from PacifiCorp's final license application, and subsequent filings with FERC. Measures include installation of a synchronous bypass valve at J.C. Boyle, and various fish and wildlife, recreational, and other enhancements. Costs for some specific maintenance events expected over the next license term had to be excluded from the list, since the schedule is not clear, and no cost estimates are available. Since runner replacements and generator overhauls will likely be needed, the total cost of measures in this category is likely conservative.

Federal Power Act Mandatory Conditions[36]: On March 27, 2006, federal agencies filed preliminary mandatory conditions under the Federal Power Act (16 U.S.C. 797(e), and 16 USC 811). Reclamation and BLM filed preliminary conditions to protect lands they manage that are affected by the hydro project. The main feature of the BLM preliminary mandatory condition is an increased allocation of available water to the river to enhance salmonid habitat, and a decreased allocation to the powerhouses. This operational requirement was calculated separately using the hydrological model discussed in Chapter 2. Other elements of the BLM preliminary conditions were largely excluded from the Relicensed Condition due to the absence of specific engineering cost estimates. No costs are included in the Relicensed Condition from Reclamation's preliminary conditions, which were mainly administrative in nature.

FWS and NOAA Fisheries filed preliminary mandatory fishway prescriptions for volitional upstream and downstream passage past four power dams (fish ladders), including spillway and tailrace improvements. Costs in the Relicensed Condition are based on specific engineering cost estimates prepared by CH2MHill for PacifiCorp, and filed with the federal agencies in April 2006.

PacifiCorp has proposed a trap and haul fish passage program as an alternative to the fish passage measures proposed by the agencies. Since the Relicensed Condition is based on the preliminary agency conditions, the PacifiCorp trap and haul alternative is not included in this model run. PacifiCorp has nominally estimated their alternative at $52 million.

Clean Water Act Certification: Section 401 of the CWA (33 USC §1341) requires that applicants for a federal license, or permit for activities which may result in a discharge

[36] Under Federal Power Act sections 4(e) and 18, federal land management and fisheries agencies have an independent authority to develop and require mitigation for natural resources damaged by federally-licensed hydropower operations. By law, FERC is required to adopt such "mandatory conditions" into its hydropower licenses. A similar "mandatory condition" authority is vested with state water quality agencies under section 401 of the Clean Water Act. Sections 10(a) and 10(j) of the Federal Power Act authorizes state and federal wildlife and natural resource agencies to recommend additional mitigation and enhancement measures, but FERC is not obligated to adopt these measures into final licenses.

to navigable waters, must obtain certification that these activities will be in compliance with applicable water quality standards. Water released from hydropower turbines are classified as such a discharge. Under Section 401, state agencies are authorized to grant, waive, or deny water quality certification. State water quality agencies make independent findings on how hydropower facilities affect water quality and have an independent authority to impose operational changes and physical changes to the hydropower facilities.

PacifiCorp has filed applications for certification with the State Water Resources Control Board in California, and the Department of Environmental Quality in Oregon. Since the certification process is just getting underway, the full cost of measures to avoid, minimize or compensate for impacts is not known. Impacts that may need to be addressed include altered water temperature, reduced dissolved oxygen levels, and nutrients and nutrient cycling. The Relicensed Condition includes the oxygen diffuser system that was proposed by PacifiCorp at Iron Gate, and temperature control devices at Iron Gate and Copco 2. The cost estimates for the temperature control devices were prepared by PacifiCorp in an August 2005 report to FERC. For the purposes of this analysis, those devices serve as proxies for what is likely to be a suite of measures developed through the certification process.

<u>Federal Power Act Fish and Wildlife Recommendations:</u> On March 27 2006, the federal and state fish and wildlife agencies (FWS, NOAA Fisheries, CDFG, and ODFW) submitted to FERC recommendations under the Federal Power Act to adequately and equitably protect, mitigate damages to, and enhance fish and wildlife (including related spawning grounds and habitat) (16 USC 803(j)). These measures included monitoring of the fish passage program, gravel augmentation, and riparian habitat restoration. Some of these measures will ultimately be adopted by FERC, and others will not. In addition, specific engineering cost estimates were not available for most of these recommendations. The Relicensed Condition contains an estimate, based on the best information available, of what could be included in the license based on agency fish and wildlife recommendations. Significant line items include ongoing operation of Iron Gate Hatchery with additional fish marking and effectiveness monitoring for fishways. The majority of the agency recommendations were excluded from the Relicensed Condition due to a lack of sufficiently detailed cost estimates.

2. Unrecovered Undepreciated Investment

The value of the Klamath Hydro Project is a depreciable asset, so at decommissioning unclaimed book value becomes a cost. Book value is a utility terms that denotes the recoverable capital costs owed to shareholders. Table 3-3 includes the infrastructure investment status for JC Boyle, Copco I & II and Iron Gate.[37] The initial investment from the 2004 FERC Form 1 filing is $60.7 million, whereas $38.5 million is remaining book value. It is important to note that the recent upgrades to JC Boyle that produced the 10 MW capacity increase are not yet

[37] In the model, the *Form 1* tab shows these values.

included in the book value. These values will also need to be adjusted downward to conform with PacifiCorp data for remaining value on the date of decommissioning, e.g., 2013. This non-recovered investment could be a potential cost to ratepayers if the OPUC and CPUC order recovery of these assets through rates. This cost would then be additive to the other decommissioning costs discussed below.

Another perspective is that this cost is "sunk", i.e., that it already has been incurred and will be paid no matter what the policy decision is going forward. Given this perspective, this unrecovered investment should not be included in the cost for decommissioning, which would reduce the decommissioning cost estimate by $39 million. The allocation of this cost would then be an equity issue between PacifiCorp's shareholders and ratepayers that would be independent of the decommissioning decision. As a conservative assumption, the unrecovered investment is included as a potential decommissioning cost element.

Table 3-3: Non-Recovered Depreciation on Infrastructure for the Decommissioning Scenario (2005$ Millions)

	Total	JC Boyle	Copco 1	Copco 2	Iron Gate
Total Infrastructure Cost	**$60.7**	$26.1	$8.7	$9.1	$16.9
Accumulated Depreciation	**$22.2**	$8.1	$4.8	$3.3	$6.0
Net Book Value	**$38.5**	$18.0	$3.9	$5.7	$10.9
Production Expenses	**$3.7**	$1.3	$0.6	$0.8	$0.9

3. Dam Removal

As an alternative to relicensing, numerous parties have proposed the removal of the four dams and power generation facilities below Keno Dam. The final decision on whether to decommission the project will be made by PacifiCorp, either in the context of the settlement negotiations or in response to the new FERC license conditions. The precise timing and sequence of this decommissioning has not been specified. The scenario used in this run of KPAAM was developed by the modeling team. It is a conceptual approach that is intended to be representative of potential future costs. More comprehensive decommissioning, sediment management and site restoration studies managed by the Coastal Conservancy are continuing. Additional KPAAM scenarios can be developed to analyze revised schedules and decommissioning cost estimates as new information is generated through any further planning, engineering and permitting work.

This run of KPAAM uses a decommissioning cost estimate developed for the California Coastal Conservancy that was most recently updated in September 2006. [38] The nominal dollar estimate is $89.6 million.[39] This estimate is an adjusted

[38] Personal Communication, Michael Bowen, California Coastal Conservancy, November 13, 2006. A revised preliminary estimate was released in October 2006. Structural removal costs are estimated to be $50 million. Water use mitigation, engineering and permitting, and construction management raise the total current revised estimate to $87.9 million. These continuing studies confirm the magnitude of the initial estimate. To be conservative, until more details are available on the new study, the higher cost estimate is used here.

amount based on an initial study sponsored by the Conservancy released in 2005. The updated estimate is for demolition and removal of the four dams, and includes other overhead costs and factors such as permitting, engineering and construction management. A key finding in the Conservancy's most recent sediment report and cost estimate is that the sediments are clean enough to allow for down-river dispersal. The removal schedule and costs used for initial results is shown in Table 3-4. Note that these are nominal costs that will be appropriately discounted in Chapter 4.

An important assumption in the model is that current license conditions will remain in place until decommissioning begins. However, interim conditions may be proposed that are not yet depicted in the model.

Table 3-4: Decommissioning Assumptions

Decommissioning Schedule	**Start Year**	**Nominal Engineering Cost ($millions)**
J.C. Boyle	2014	12.1
Copco I	2013	14.0
Copco II	2013	14.0
Fall Creek	2015	2.0
Iron Gate	2015	49.5
Nominal Total		89.6

4. Replacement Power

FERC traditionally has relied on a "current cost" of electricity estimate, typically presented by the license applicant, to estimate the power benefits derived from the power project. Unfortunately, this approach assumes that a "current" cost is available and relevant when in fact no such data is actually available—the supplied data is just another form of a forecast. It also is based on the false premise that historic embedded costs, which can be calculated to derive an "average" cost, are representative of the replacement cost for power. What license applicants, including PacifiCorp in this FERC proceeding, have presented as a "current" value is actually a one-year forecast derived from modeling. It is not a "recorded" cost or even necessarily a "market quote."

Even though FERC has attempted to remove the issue of forecast uncertainty from its relicensing cases, the issue cannot be avoided—*some* assumption must be made about the future value of power when conducting an economic analysis of a project with a 30 to 50 year life. As presented here, FERC can rely on a different approach to balance the benefits of power production with the other benefits and costs of the project. FERC can explicitly address the uncertainty associated with future power values by using a range of power forecasts rather than trying to ignore them with an inadequate "fix".

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[39] In addition, four decommissioning schedules are built into the model though only the one schedule is used for this version of modeling results.

This report presents a set of power value forecasts that FERC may use in its relicensing proceeding. These forecasts were prepared in 2005 and 2006 by various energy planning agencies, and by PacifiCorp in other proceedings. They are representative of the costs to construct and operate new generation resources that are needed to meet growth in electricity demand. They are also representative of procurement costs, which are the costs for utilities such as PacifiCorp to purchase electricity from other public and merchant generators.

One issue not addressed here is how to treat the value of the Klamath Project generation capacity. Firm capacity, also known as dependable capacity, is valued more highly in energy markets that non-firm or intermittent capacity. Thermal and nuclear generating units have firm capacity that can be scheduled and dispatched according to load demands. This is especially important in regions where peak demands for summer cooling or winter heating are substantially higher than off-peak demand. Generation from resources such as hydropower and wind depend on hydrology and weather patterns that vary over time. Electricity from these types of generation resources are often not rated as firm or dependable, or their ratings are lower than their nameplate capacity. Accordingly, they have lower value in the energy markets.

Preliminary analysis indicates that the amount of firm capacity to meet summer time peak loads under critically dry conditions—a criteria used by various energy agencies in the Northwest and by the Western Electricity Coordinating Council (WECC) to establish reliable capacity—is substantially less than the Klamath's total project generating capacity. PacifiCorp asserts that all 169 MW of nameplate capacity for the Klamath Hydro Project is firm capacity. In contrast, the assessment of available regional generation resources prepared by the Northwest Power Planning Council indicates a lower level of reliability for the Klamath Project. It has a firm capacity rating of 92 MW.[40] FERC rates the dependable capacity for the Klamath Project at 42.7 MW in the 2006 DEIS. For this reason, it may not be appropriate to apply firm power values to the generation from the Project for valuation purposes. If this is the case, the various replacement cost forecasts must be decomposed into their firm-capacity and energy-only portions, and only the latter applied to generation above the firm-capacity level. For most of the forecasts discussed below, this decomposition is readily available, including for the PacifiCorp forecasts.

It is also important to remember the appropriate electricity production baseline to use in comparing the relicensing and decommissioning scenarios. This study does *not* calculate the costs of replacing current or historic levels of generation. In no case will PacifiCorp be able to rely on that amount of generation in the future because the project does not meet current environmental regulatory standards. Moreover, PacifiCorp is not entitled to be compensated for any such loss of generation because its FERC license allowing for current production levels will soon expire: PacifiCorp's property right in the Klamath Project expires with the old license. The purpose of a FERC relicensing proceeding is to establish the appropriate mitigation measures and operations standards for old hydropower projects and bring them into legal

[40] As listed in "Res 121504 HYLoss.xls" at www.nwcouncil.org

conformance with modern environmental science and regulation. The appropriate future alternative is the amount of generation expected under the relicensed terms with the appropriate mitigation measures. As shown in Tables 2-4 and 2-5, this will lead to reduced generation and a reduced ability to meet peak demands under adverse hydrologic conditions, which is the usual standard for measuring peak output.

The Department of Interior and State of Oregon also presents values for replacing power with resources *other* than "traditional" generation plants.[41] While Energy Commission staff has not yet reviewed these values in sufficient specificity, approaches such as those including demand-side management (DSM) measures are consistent with California's policy on resource "loading order" as expressed in its Energy Action Plan.

Replacement power costs are estimated for both mitigated relicensing and decommissioning scenarios by multiplying levelized replacement power costs ($/MWh) by lost hydroelectric power production (MWh) for each year of the study period.

Decommissioning still involves several years of "as usual" power production. This is "extra" power generation above what would have occurred under relicensing that yields net revenues equal to replacement power costs minus the costs of power generation at each Klamath development (see Table 3-3.)

Forecasted costs are provided in nominal dollars, but are inflated to 2005$ and levelized over the study period, which is currently set at 30 years, 2008 through 2038.

Modeling results are presented for the five replacement power cost forecasts, though several additional power price forecasts are included in KPAAM. Replacement power costs and natural gas price forecasts are shown graphically in Figures 3-1 and 3-2, respectively, and transformed to a "levelized"[42] metric of dollars per megawatt-hour ($/MWh) in Table 3-5.

Natural Gas Price Forecasts

Perhaps the central driver of any replacement cost or avoided cost forecast is the natural gas price for fueling the dominant generation resource added to meet incremental load in the West. For example, in the Energy Commission replacement cost estimates developed for use in the Integrated Energy Policy Report, natural gas represents more than 75 percent of the cost share. This characteristic is evident

[41] Replacement Power Values, Office of Policy Analysis, Department of the Interior, March 27, 2006, and Personal Communication, David Stewart-Smith, affiliation?, date?

[42] The "levelized" metric transforms the cost, which may be comprised of capital and operational costs over a period of several decades, into an annual payment per MWh in present value terms based on a payment time period (i.e., number of payments) and time discount rate. This creates the equivalent of a "mortgage payment." Levelization in the KPAAM model uses a 30-year payment period and a Weighted Average Cost of Capital (WACC) at 9.08% based on the discount rate used by PacifiCorp in its marginal costs filing with the Oregon PUC in UE-179.

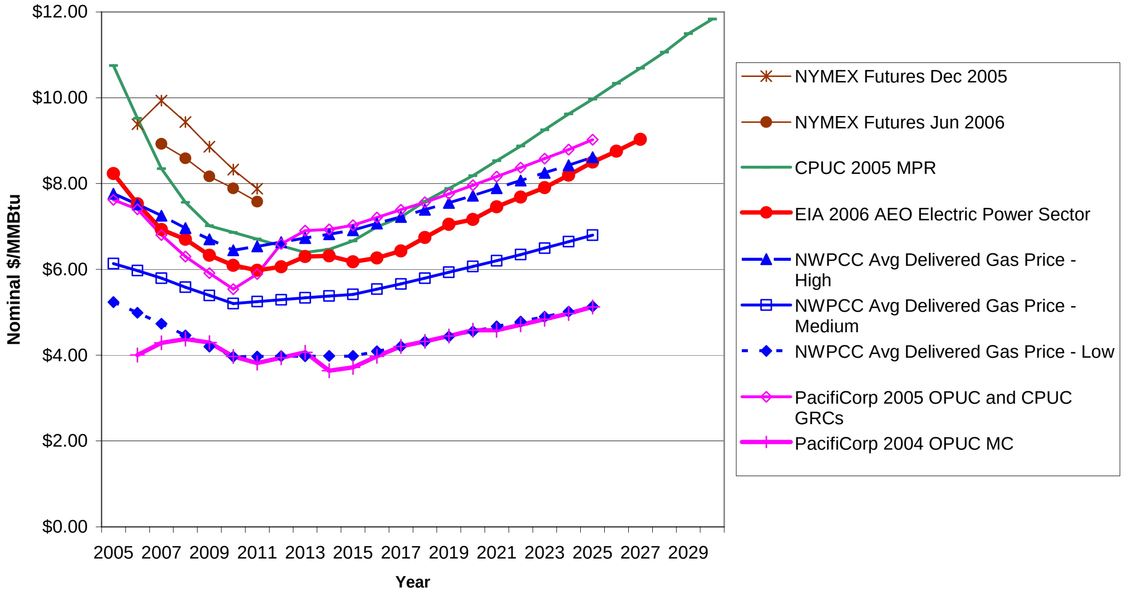
whether the electricity cost forecasts look at the system as a whole or identify a single resource. Combined-cycle gas-fired plants have been the power source of choice for a variety of reasons, both financial and environmental.

Forecasts for 2005 to 2025 in nominal dollars from several sources are presented in Figure 3-2:

- Energy Information Administration (EIA) of the U.S. Department of Energy, *Annual Energy Outlook 2006*;[43]
- Northwest Power and Conservation Council (NWPPC), *5th Power Plan*--The NWPPC *5th Power Plan* includes low, medium and high price scenarios, and distinguishes by delivery region. We provide high, medium and low prices averaged for deliveries on the east and west sides of the Cascade Mountain Range;[44]
- The forecast used by the California Public Utilities Commission to set the Market Price Referent used as the reasonableness standard for approval of new renewable power contracts to meet the Renewable Portfolio Standard (RPS);[45]
- Two forecasts from PacifiCorp in proceedings at the Oregon Public Utilities Commission (OPUC),[46] and the California Public Utilities Commission (CPUC);[47] and
- New York Mercantile Exchange (NYMEX) futures markets in December 2005 and June 2006.[48]

[43] Early Release Date: December 12, 2005.
[44] Publication: May 2005, forecast from April 2002.
[45] CPUC Resolution E-3980, R.04-04-026, April 2006.
[46] PacifiCorp, "Marginal Generation Energy Costs," *Marginal Cost Study*, OPUC Docket UE-170, November 2004; and PacifiCorp, OPUC Docket UE-179, November 2005.
[47] PacifiCorp, "Marginal Generation Energy Costs," *2007 General Rate Case Exhibit PPL/1202*, CPUC Docket A.05-11-022, November 2005.
[48] Source: http://futures.tradingcharts.com/marketquotes/NG.html. These prices were available only to 2011.

Figure 3-2: Natural Gas Price Forecasts, 2005 – 2030



Note that even though the EIA forecast was completed almost three years after the NWPPC forecasts, it still lies within the bounds of the NWPPC forecasts, and near the mid-point forecast over the time horizon. Interestingly the PacifiCorp forecasts track the low and high NWPPC forecasts. The 2005 forecasts for the OPUC and CPUC proceedings are identical and near the high end of the bounded range, while the 2004 OPUC forecast is at the lower end. The divergent outlooks on the gas market are quite evident after 2011.

Generation Replacement Costs

Power generation cost estimates based on wholesale market forecasts were presented in various forums in the West over the last year.[49] Forecasts vary by the underlying assumptions about future replacement power technologies, discount rates, and natural gas prices. The forecasts are reported in nominal dollars as they appeared in published documents. Several replacement power forecasts were gathered from published sources for the KPAAM, as shown in Figure 3-3:

- U.S. Department of the Interior (DOI) – Current power replacement cost from range of sources as documented in its March 29, 2006 filing with FERC. This is a mid-range of estimates that include long-term forecasts and current prices.
- Northwest Power Planning Council (NWPPC) – Drawn from the *Fifth Power Plan* released in 2003. The forecast is based on wholesale Mid Columbia spot market for mix of resources in PNW. This forecast may underestimate new resource cost due to assumptions about optimal energy efficiency and renewable resource investments.

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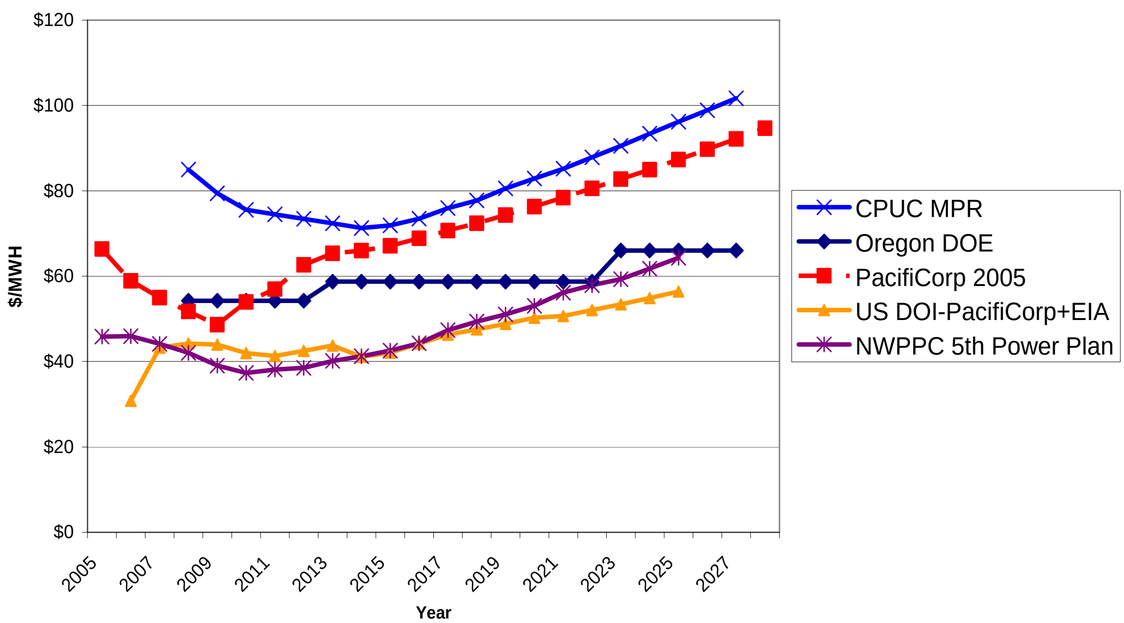
[49] All dollar values were adjusted from constant dollar base years where appropriate using the Energy Commission's GDP implicit price deflator.

- PacifiCorp — Drawn from submitted filings by PacifiCorp with the California and Oregon Public Utilities Commissions for marginal costs and avoided costs in two rate cases in November 2005.[50]
- California Public Utilities Commission (CPUC) Market Price Referent (MPR) — Based on a combined-cycle gas turbine plant on the margin 88 percent of year, used to benchmark renewable generation bids.[51] This proxy may overestimate long-run new resource costs.
- DOI-PacifiCorp+EIA – Created by the DOI from PacifiCorp 2004 marginal cost filings[52] with the Energy Information Administration's *Annual Energy Outlook* 2006 gas price forecast: Marginal costs are based on combined-cycle gas turbine plant.
- Oregon Department of Energy (ORDOE)– based on a 50 percent biomass generation and 50 percent demand side management (DSM) with specific resource replacement.[53]

Figure 3-3: Comparison of Replacement Cost Forecasts, 2005 - 2030[54]



[50] PacifiCorp, *2007 General Rate Case Exhibit PPL/1202*, CPUC Docket A.05-11-022, November 2005, Table 5, and UE-179 at the OPUC.
[51] Resolution E-3980 in R.04-04-026.
[52] PacifiCorp, *Marginal Cost Study*, OPUC Docket UE-170, November 2004.
[53] This is an informal proposal in which a 40 MW forest-residue-fueled biomass plant would be constructed in the Klamath region, and another 325 GWh of DSM would be identified and implemented in state-owned government facilities within Oregon.
[54] The DOI forecast is not included because it is based on a compilation of levelized-cost estimates for various resources and does not have an evident time trend for comparison.

PacifiCorp filed its forecasted generation marginal costs with the OPUC for its rate cases in November 2005 for the period to 2025.[55] PacifiCorp also filed a generation marginal cost forecast from 2007 to 2016 in its 2007 General Rate Case before the CPUC.[56] This forecast is used for revenue allocation among retail customers and retail rate design. PacifiCorp distinguishes between on and off peak, but KPAAM contains an average. On-peak premiums are about $10/MWh more in the near term, and grow to $30 by 2025.

Another avoided cost estimate was published by the NWPPC in their Final *5th Power Plan*.[57,58] The NWPPC cost forecast spans 2005 to 2025.[59] NWPPC reported avoided costs for four regions: West of Cascades, MidColumbia (Eastside), Southern Idaho and Eastern Montana. Given the location of the Klamath complex, only costs for the MidColumbia region are used in KPAAM. The NWPPC forecast is inflated to 2005$ dollars using an inflation rate of 2.8 percent.

The Oregon DOE forecast is built upon the assumption that demand side management projects will cost $2,000 per kW and last for 15 years, yielding a levelized cost of $28.46 per MWh.[60] The DSM proposal is derived from a review of PacifiCorp energy efficiency plans and identifying what additional measures are available to be implemented. The biomass plant cost estimate is based on analysis prepared for the Oregon Department of Energy.[61]

The DOI / PacifiCorp forecast was constructed by the Department of Interior's economist to meld the gas price forecast from the EIA's *Annual Energy Outlook* with PacifiCorp's assumptions about the construction and operating costs for a new resource in its rate case filings referenced above.

Looking at Figure 3-2, even in the near term, the range across forecasts is substantial, from $42 to $85 per megawatt-hour (MWh) in 2008, and increasing as several forecasts decline while other rise. Two 2005 PacifiCorp forecasts—one issued in July but not shown here, and the two November filings—differ by $12 per MWh despite relying on the same underlying gas price forecast.

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[55] PacifiCorp, *Marginal Cost Study*, OPUC Docket UE-179, November 2005.

[56] PacifiCorp, *2007 General Rate Case Exhibit PPL/1202*, CPUC Docket A.05-11-022, November 2005, Table 5.

[57] NWPPC, *5th Power Plan*, Volume 3, Appendix C: Wholesale Electricity Price Forecast. (Revision #R5B11, see http://www.nwcouncil.org/energy/powerplan/plan/Default.htm).

[58] In addition to the "Final Base" from Dec. 7, 2004 reported here, the NWPCC presents several alternative cost estimates: Current Trends 022004 (5th Plan Draft); 5th Plan Final Base 120704; 5th Plan Final Med-low Demand from March 30, 2005; 5th Plan Final Med-high Demand from April 10, 2005; 5th Plan Final LoFuel Price from March 17, 2005; 5th Plan Final HiFuel Price from March 16, 2005.

[59] An extended forecast out to 2055 also have been developed by the NWPPC but is not presented here. These estimates were reported in 2000 dollars, so they were inflated to a 2005 base year using the 5-year increment from the Energy Commission 2004 Implicit Price Deflator.

[60] This cost estimate is based on information provided by Guy Phillips, and David Stewart-Smith of Pacific Energy Systems, Inc.

[61] This cost estimate developed by David Stewart-Smith of Pacific Energy Systems, Inc.

In the long term, the disparity is even more evident. The NWPPC foresees a generally flat trend as new coal-fired and wind generators displace more costly gas-fired plants after 2011. The CPUC and PacifiCorp forecasts presume that gas-fired generation remains the primary source of power and thus rise dramatically in future years. The CPUC forecast is driven by an increasing natural gas price, as shown in Figure 3-1, but this it not true for the PacifiCorp forecasts. Instead, the root difference between the NWPPC and PacifiCorp forecasts is created by a different assumption about the cost and implicit value of added capacity, with PacifiCorp assuming a much higher cost for acquiring a new power plant.

In addition, several near term contract rates for Southern California Edison Co. (SCE), Los Angeles Department of Water and Power (LADWP) and the Bonneville Power Administration (BPA) are shown as reference points. These represent expectations and availability of power at the prices reflected in the other forecasts used in this analysis:

- PacifiCorp has the option to purchase power from the Bonneville Power Administration (BPA) under the New Resource (NR) wholesale tariff. to replace lost Klamath generation The rates shown are for the existing NR-02 rate for 2006, and the proposed NR-07 rate for 2007 through 2009. In developing the NR rate, BPA forecasts wholesale power costs through 2009. The analysis relies on a complex computer model of the Northwest system in a similar fashion to the forecasts developed by PacifiCorp and the NWPPC. What that cost may be is a bit uncertain because PacifiCorp may be able to mitigate some of that cost through the Residential Exchange program. As envisioned in the Northwest Power Act, PacifiCorp is able to sell to BPA power at its average system cost equivalent to the amount it delivers to its residential customers.[62] In turn, PacifiCorp is able to buy back power from BPA at a rate about equivalent to BPA's Residential Load (RL) rate that is slightly higher than the Priority Firm (PF) rate for deliveries to public utility customers.[63] The RL and PF rates are about one-half the cost of the NR rate.[64] The terms of the Residential Exchange program have not yet been established and additional information is needed about PacifiCorp's eligible load to calculate the expected replacement cost under

[62] "Purchase and exchange sales. Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region." (U.S. Code, Title 16, Chapter 12, § 839c (c)(1), http://www.law.cornell.edu/uscode/html/uscode16/usc_sec_16_00000839---c000-.html).

[63] "This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest. The Residential Load (RL) Firm Power Rate is available to investor-owned utilities (IOU) under net requirements contracts for resale to ultimate residential consumers for direct consumption. Further, in order to purchase under this rate, the IOU must agree to waive its right to request benefits under section 5(c) of the Northwest Power Act for the term of the contract. Each IOU will be able to purchase a specified amount of Firm Power at the RL-02 rate. Additional sales of requirements power to IOUs will be made at the NR-02 rate." (BPA, "Residential Load Firm Power Rate, "*2002 Wholesale Power Rate Schedules (WP-02), 2002 General Rate Schedule Provisions, Revised FY 2003 Firm Power Products and Services Rate (FPS-96R) General Transfer Agreement Delivery Charge,* Revised May 2004).

[64] *Ibid.*

the terms of the BPA contracts. The NR rate proposed by BPA is subject to litigation and change, but the values presented here are representative of the expected final rates.

- PPM, the former merchant plant developing affiliate of PacifiCorp (before the latter's sale to MidAmerican), signed a long-term power contract for wind power with LADWP. The reported price is $63 per MWh for 16 years.[65]
- SCE presented an average of quotes for forward contracts offered at the SP-15 delivery point in the California Independent System Operator (CAISO) control area for the 2006 to 2008 period.[66]
-

Table 3-5: Simple Levelized 30-Year Replacement Cost Forecasts[67] (2005$)

Agency Forecast	$/MWh
PacifiCorp July 2005 to OPUC Avoided Costs	$66.10
US Dept. of Interior March 2006 FERC Filing	$37.00
NWPPC 5th Power Plan Base Forecast	$44.59
US DOI-PacifiCorp Avoided Cost + EIA Gas Price	$45.25
Oregon DOE (Biomass + DSM = 60 aMW)	$58.18
CPUC Market Price Referent (Gas Combined Cycle)	$79.44
Current Rates & Prices (2006)	
BPA New Resource Wholesale Rate	$53.22
BPA Melded NR/RE Wholesale Rate	$43.79
PPM Energy-LADWP 16-Yr Wind Power Contract	$63.00
SCE SP-15 Forwards (2006-2008)	$69.18

Each of these forecasts is based on different assumptions about the fundamentals of the marketplace and different assumptions about near-term and long-term mixes of generation resources; and each is likely to be making different simplifying assumptions or even ignoring different aspects that influence the results.

In depicting differences between historic, current and future power production by the Klamath Project, it is important to recognize shifts in the timing of production. As discussed above in the Scenario Summaries section, the KPAAM model calculates the differences in peak and non-peak power production relative to historic production for both the current operating conditions and relicensing.

[65] Reuters, "LADWP to buy 82 MW a year in 16-yr deal with PPM," June 6, 2006.
[66] *Southern California Edison Company's (U 338-E) Supplement to Its Proposal for Benchmarking and Evaluating Time-of-Delivery Profiles*, Rulemaking 04-04-026, February 8, 2006, p. 4.
[67] The values in Table 3-5 are solely for illustrative purposes to summarize the underlying annual forecast values shown in Figure 3-2. These are a simple levelized average price that does not account for variations in generation produced or purchased over the time horizon. This differs from the calculation presented in Chapter 4, so that the values shown here are not directly comparable nor are they valid for direct analysis.

A second adjustment reflects the “firmness” of replacement power relative to Klamath development power. Price forecasts for firm power may not match the intermittent nature of Klamath power production. The Klamath development relies on water flows, so the nameplate production capacity of 169 MW is not assured in dry water years. When water is plentiful in the winter, firm capacity is estimated at 92 MW. Replacement power cost forecasts generally assume firm power; for example, a natural gas-fueled power plant is not subject to hydrologic variability, so the power can be considered “firm.” Power from the Klamath development in the summer is not firm capacity since it may be minimal during droughts.

KPAAM includes an editable parameter to depict the replacement cost “discount” for replacement power that is non-firm, though the discount rate is current set at 0 percent (i.e., no discount).

CHAPTER 4: RESULTS SUMMARY AND UNCERTAINTY ANALYSES[68]

This chapter describes initial results of the Klamath Project Alternatives Analysis Model (KPAAM) for several different replacement power cost forecasts. Because we cannot forecast future conditions and final costs with certainty—or even any reasonable precision—we report a range of potential costs to capture reasonable bounds on what could happen. It is important to remember that no single forecast presented here is a valid expectation of the future. Rather, the range provides guidance on what type of prudent decision can be made, and also identifies potential risks that may necessitate risk sharing among the parties.

Results Calculation Method

The model calculates the net present value (NPV) of the various cost components for the relicensing and decommissioning project alternatives described in Chapters 2 and 3 over a 30-year period. Given the long 30-year period over which costs are incurred at different points in time, it is critical to convert all costs to constant 2005$ through the net present value calculations to allow for economically accurate comparisons between the Relicensing and Decommissioning Conditions. KPAAM is sensitive to the timing of cost expenditures and ongoing revenues, reflecting the importance of appropriate discounting methods.

KPAAM is then used to compare total NPV decommissioning costs and relicensing costs to show the net cost to PacifiCorp ratepayers. If the net present value of relicensing costs minus decommissioning costs is greater than zero, then decommissioning is less costly than relicensing. Where the net value is negative, decommissioning is more costly than relicensing. Note that decommissioning includes the remaining book value and replacement power costs.

Mathematically, the equation comparing decommissioning costs with relicensing costs is:

+ (Relicensing mitigation costs + Ongoing O&M costs)
<u>- (Dam removal costs + Remaining book value + Replacement power costs)</u>
= Net Present Value Relicensing minus Decommissioning

[68] Primary technical contributions by Richard McCann and James D. Fine, M.Cubed

Also included in the summary results is a “Break Even” calculation that shows, in levelized dollars per MWh, the cost of replacement power that would make decommissioning costs equal to relicensing costs.

Net Present Value Calculations for Decommissioning

Total decommissioning costs for a range of replacement power forecasts are shown in Table 4-1 as the net present value sum of the dam removal costs *plus* unrecovered, undepreciated investment. The midline case for NPV costs total $9494 million. The uncertainty in total decommissioning cost estimates given the preliminary phase of planning and engineering is reflected in the range from low to high from $77 to $110 million.

Table 4-1: Total Net Present Value Decommissioning Costs (Millions of 2005 Dollars)

Decommissioning Cost Item	Low	Medium	High
Dam Removal Costs	$39	$55	$72
Remaining Net Book Value	$39	$39	$39
Total Decommissioning Costs	$77	$94	$110

Net Present Value Calculations for Replacement Power

Next, KPAAM is used to calculate net present value costs for the six replacement power levelized cost estimates shown in Table 3-5. The model adjusts for the higher generation levels prior to decommissioning in the years 2008 and 2013, where generation continues with the 2012 BO Flow Regime, and is higher than generation with the relicensing conditions. This factor reduces near-term replacement power costs and weights the differences in power values over time. For this reason, the power values in the final results differ from the simple average levelized forecast prices shown in Table 3-5.

The NPV results in Table 4-2 are shown as adjusted, weighted levelized costs in dollars per MWh, and in 30-year lump sum totals for the period 2008 to 2038. The 30-year total costs account for revenues from ongoing generation between 2008 and 2013, assuming no interim mitigation and the 2012 BO Flow Regime, when decommissioning is assumed to begin. Using PacifiCorp’s levelized, weighted 30-year cost for replacement power of $78.98 per MWh from its 2005 filing with the Oregon PUC as an example, the model shows that total 30-year replacement power costs would be $165 million in 2005 dollars.

Table 4-2: Net Present Value Totals for 30-Year Replacement Power Costs (2005 Dollars)		
Replacement Power Cost Estimate	Adjusted $/MWh	30-Year Total Replacement Power Costs (Millions)
US DOI	$35.59	$74
US DOI-PacifiCorp+EIA	$47.15	$99
NWPPC 5th Power Plan	$51.56	$108
Oregon DOE	$59.76	$125
PacifiCorp 2005	$78.98	$165
CPUC MPR	$79.73	$167

Combining Net Present Value Replacement Power and Decommissioning Costs

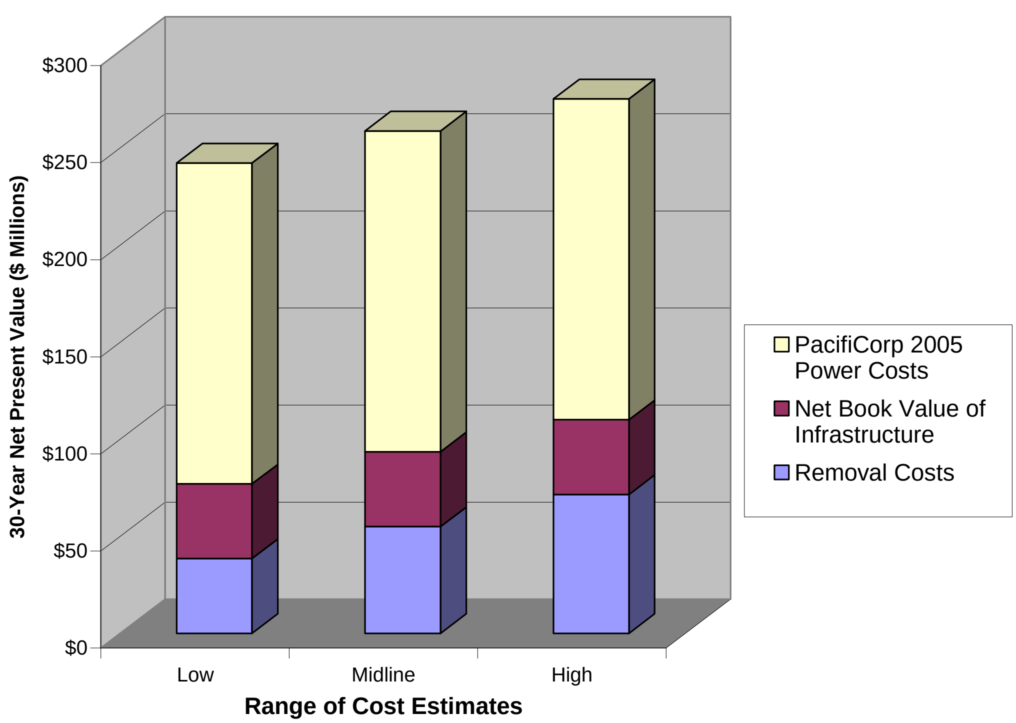
The total NPV replacement power costs are then added to the NPV decommissioning costs, as shown in Table 4-3. Decommissioning costs are shown in the top row, while relicensing mitigation costs are shown at the bottom for comparison. The range of 18 values in the table reflect real world uncertainty in the decommissioning cost estimates and the different assumptions used by energy planners in developing forecasts for replacement power. Recall from Chapter 3 that the PacifiCorp and CPUC MPR forecasts assume combined cycle natural gas-fired power plants as the future preferred resource, while the Northwest Power Planning Council forecast reflects a portfolio of future generating resources in the Northwest that would include lower cost wind and coal.

Note that the highest cost scenario in the table—$277 million NPV using the CPUC MPR price forecast and the high decommissioning cost estimate—is only $47 million greater than the lowest relicensing mitigation measure cost of $2303 million NPV. In other words, the range of potential costs for decommissioning apparently lies below that for relicensing with little overlap. Decommissioning is likely to cost *less* than $277 million, while relicensing is likely to cost *more* than $230 million.

Using PacifiCorp's replacement power forecast and the midline decommissioning case as an example, total decommissioning and replacement power costs are $259 million in 2005 dollars. In comparison, the midline relicensing case totals $360 million. Figure 4-1 shows the distribution of costs for the scenario using PacifiCorp's replacement power cost forecast.

Table 4-3: Total Costs of Decommissioning: Dam Removal plus Replacement Power (Millions of 2005 Dollars)				
Total Decommissioning Costs		***Low***	***Midline***	***High***
		$77	*$94*	*$110*
Replacement Power Cost Forecast	**30-Year Total Replacement Power Costs**	**Replacement Power plus Dam Removal Costs**		
		Low	**Midline**	**High**
US DOI	$74	$152	$168	$185
US DOI-PacifiCorp+EIA	$99	$176	$192	$209
NWPPC 5th Power Plan	$108	$185	$201	$218
Oregon DOE	$125	$202	$219	$235
PacifiCorp 2005	$165	$242	$259	$275
CPUC MPR	$167	$244	$260	$277
Relicensing Mitigation Costs		**$230**	**$360**	**$470**

Figure 4-1: Range of Decommissioning with Replacement Power Costs for 2005 PacifiCorp Replacement Power Cost Forecast



Comparing the Relicensing and Decommissioning Conditions

The objective of this study has been to develop an analytic methodology that allows for economically valid comparisons between two distinct project options for the Klamath Hydroelectric Project: the Relicensing Condition and the Decommissioning Condition. With all cost inputs for relicensing operations, mitigation, decommissioning, and replacement power now properly compiled and discounted through net present value calculations, direct comparisons of the Relicensing and Decommissioning Conditions can be made.

The mathematical expression of this comparison of the Relicensing and Decommissioning Conditions is:

+ (Relicensing mitigation costs + Ongoing O&M costs)
- (Dam removal costs + Remaining book value + Replacement power costs)
= Net Present Value Relicensing minus Decommissioning

Table 4-4 directly compares the total net present value differences for the Relicensing and Decommissioning Conditions by subtracting – or showing the arithmetic difference between – decommissioning costs and relicensing costs. A positive value means that relicensing is more expensive to PacifiCorp ratepayers than decommissioning. A negative value (in parentheses) means that relicensing is less expensive and preferable to ratepayers. The matrix of 18 resulting values expresses the ranges in replacement power forecasts and uncertainty range in decommissioning cost estimates.

Table 4-4: NPV Cost Differences Between the Relicensing Condition and Decommissioning + Replacement Power Condition (Millions of 2005 Dollars)

Replacement Power Cost Forecast	*$/MWh*	Low	Midline	High
US DOI	*$35.59*	$78	$192	$285
US DOI-PacifiCorp+EIA	*$47.15*	$54	$168	$261
NWPPC 5th Power Plan	*$51.56*	$45	$159	$252
Oregon DOE	*$59.76*	$28	$141	$235
PacifiCorp 2005	*$78.98*	($12)	$101	$195
CPUC MPR	*$79.73*	($14)	$100	$193

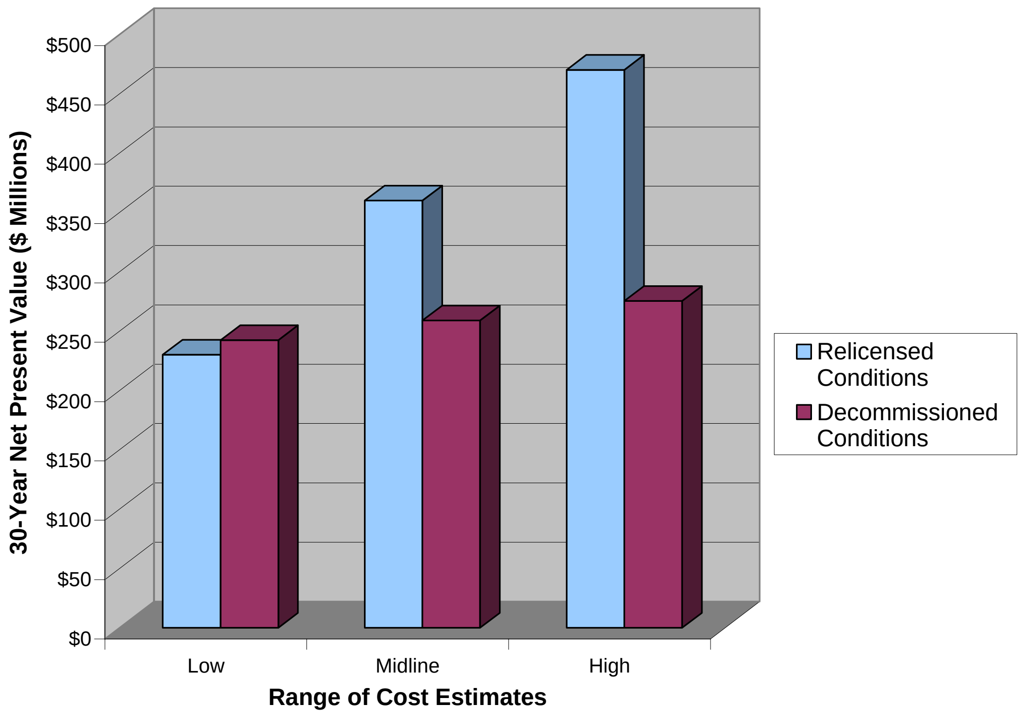
All but two of values in Table 4-4 are positive, indicating that the Decommissioning Condition is less costly than the Relicensing Condition for most of the range of replacement power forecasts and assumptions used in this run of KPAAM. This finding holds for most of the uncertainty range as well as for all midline values. As stated earlier, the range of potential costs appears to have little overlap, with those for decommissioning lying consistently below those for relicensing.

As an example of how to interpret Table 4-4: based on PacifiCorp's forecast for replacement power from its 2005 filing with the Oregon PUC (highlighted), results for the mid-line relicensing / mitigation case show that decommissioning would be $101 million less than costs for implementing mitigations measures and resulting losses in generation over a 30-year license period.

Table 4-4 also shows that the likely bounds on the estimated differences between decommissioning and relicensing range from ($14) to $285 million NPV. This is important information for decision-makers and stakeholders because it illustrates the ranges in cost differences using different assumptions for mitigation costs, decommissioning costs and replacement power costs. The intent of KPAAM is to capture and assess the wide range of opinions and assumptions held by various stakeholders involved with the Klamath Project relicensing. While there are a variety of stakeholder perspectives on what the appropriate assumptions should be for this analysis, the "true" answer is likely within this range. As stated, in all scenarios and ranges of assumptions, the decommissioning case ranges from a net cost of $14 million to ratepayers, to a net benefit of $285 million compared to the relicensing with mitigation case.

Figure 4-2 illustrates the range for a single power cost forecast scenario, based on that provided by PacifiCorp in its 2005 filing. Although this is one of the higher power cost scenarios, the relicensing costs generally exceed those for decommissioning except when decommissioning and mitigation costs are at the low end of the uncertainty range.

Figure 4-2: Comparison of Relicensing and Decommissioning Cost Ranges Using PacifiCorp's 2005 Replacement Power Cost Forecast[69]



Sensitivity of the Results to Changes in Assumptions

The changes in the power cost forecasts create a range of $92 million from the high to low scenario. This is equivalent to an increase in decommissioning costs of $2.1 million for each dollar per MWh increase in replacement power costs.[70] In this analysis with these assumptions, the uncertainty around the mitigation measures is about two and a half times larger than that for power costs at $24040 million. This is equivalent to $4 million per one percentage point change from the midline in total costs for mitigation. Similarly, decommissioning costs range over $34 million, with a response of $566,000 per percentage point change in the uncertainty range. Based on this comparison, the value of information associated with refining potential

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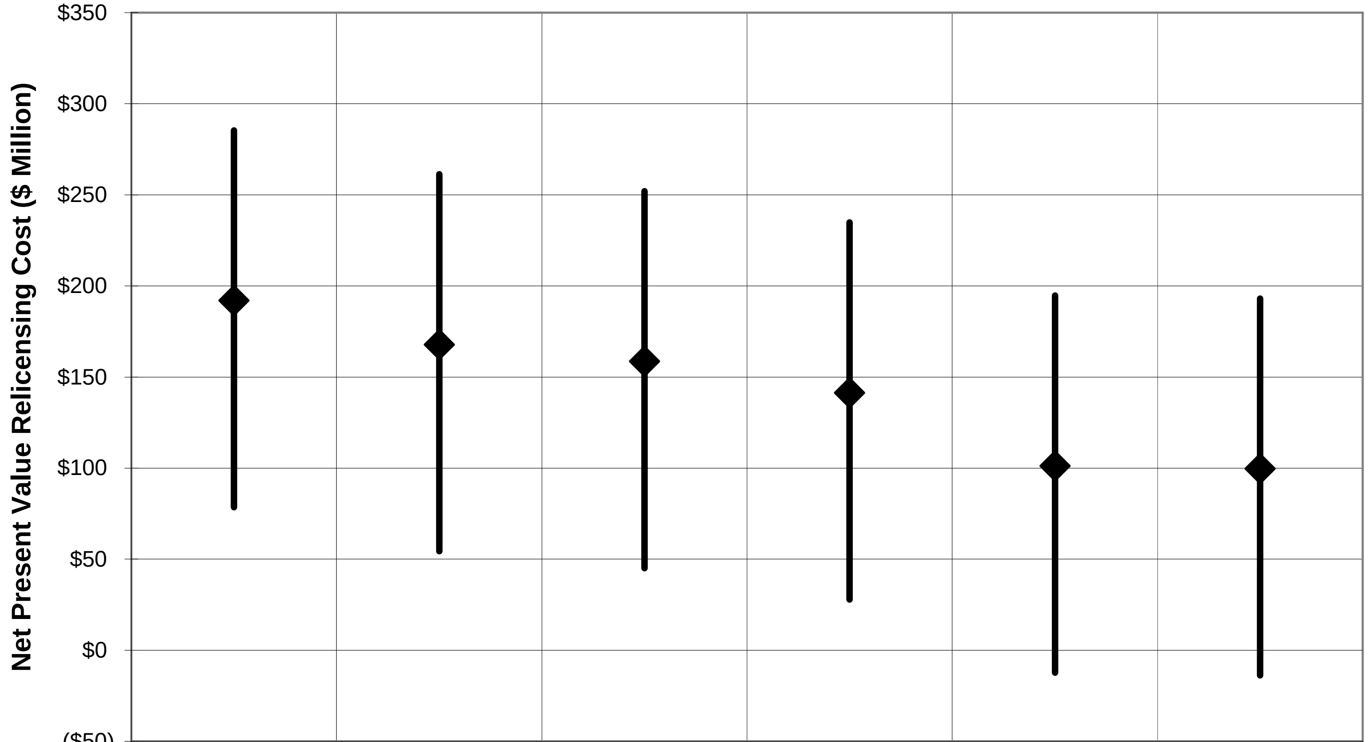
[69] Note that uncertainties associated with the relicensing range are not directly dependent on decommissioning uncertainties or vice versa, so the low-low, mid-mid and high-high comparison should not be interpreted strictly as covariance. However, there is reason to believe that to the extent that the final engineering cost estimates for either mitigation measures or decommissioning are biased high or low, the corresponding estimates for the alternative (respectively, decommissioning or mitigation measures) also will biased in the same direction. Nevertheless, once one option is chosen, we will never know if the alternative would have cost more or less than the estimate presented here.

[70] Note that the replacement power costs and the break-even costs are not directly comparable because the break-even costs includes a portion of power generation benefits created by being able to generate additional power in the period from 2008 to 2013. This offsets future replacement power costs after 2013.

mitigation costs is greater than that from gaining more accurate power price forecasts or decommissioning costs.

Figure 4-3 illustrates the ranges for all of the power cost scenarios. The advantage of decommissioning declines as the power cost forecast increases, but remains positive throughout. The importance of the replacement power forecast is evident in all of the figures. Where forecast replacement costs are lower, relicensing looks more attractive, so the “break even” replacement power cost is lower than scenarios with higher forecasted power costs.

Figure 4-3: Klamath Relicensing minus Decommissioning plus Replacement Power Cost by Power Price Forecast and Mitigation/Decommissioning Scenario



	US DOI	US DOI-PacifiCorp+EIA	NWPPC 5th Power Plan	Oregon DOE	PacifiCorp 2005	CPUC MPR
Low Costs	$78	$54	$45	$28	($12)	($14)
◆ Midline Costs	$192	$168	$159	$141	$101	$100
High Costs	$285	$261	$252	$235	$195	$193

Power Price Forecast Scenario

Calculating the Break-Even Cost Points

Another useful analysis for comparing the relicensing and decommissioning project options is to calculate the "break-even" cost points between the two. "Break-even" describes the point at which PacifiCorp ratepayers are indifferent between decommissioning and relicensing because costs are roughly equal. Put more simply, how high would replacement power costs for electricity from other sources have to be in order for ratepayers to be economically indifferent to the two project options over a 30-year period?

Table 4-4 shows the break-even replacement power costs as two 30-year metrics: the total lump sum net present value in millions, and as a levelized $ / MWh figure. For comparison, the highest cost estimate for replacement power used in KPAAM (CPUC Market Price Referent) is also shown in the table.

Table 4-4: Break-Even Cost Points for Replacement Power (Millions of 2005 Dollars)

Replacement Power Costs	Low	Medium	High	CPUC MPR Costs
30-Year Total (Millions)	$153	$266	$360	$167
Levelized ($/MWh)	$73.10	$127.33	$172.00	$79.73

The levelized break-even costs exceed all but two the forecasted values for 30-year replacement power in KPAAM, and then only in the low-cost scenario. The break-even costs exceed the highest cost replacement power cost estimate shown here (CPUC MPR) for the midline and high-cost scenarios, and by inference all of the replacement power cost estimates shown in Table 4-2. For example, the estimate using the CPUC MPR value is $99 million less than the midline value case of $266 million. Similarly, the levelized replacement cost forecasts are also lower. The CPUC MPR cost figure in 2005 dollars is $79.73 per MWh, while the midline break even cost is $127.33 per MWh.

As discussed in Chapter 3, the CPUC Market Price Referent cost reflects total capital and fuel costs for a new combined cycle natural gas power plant. For thermal generation options, this is the state-of-the-art technology. According to Table 4-4, replacement power costs would need to reach $127.33 per MWh for the low cost decommissioning scenario in order for PacifiCorp's ratepayers to be indifferent to the Relicensing and Decommissioning Conditions. In other words, the real-world cost for replacement power is nearly $48 per MWh less than the break-even cost. Interpreting this value in the context of the two Klamath project options, the break-even point is where both options have roughly the same cost. With the Relicensing Condition, ratepayers could pay up to $127.33 per MWh in the midline cost scenario and still have a hydroelectric resource that is intermittent, inflexible and non-firm, rather than electricity supplies from other resources that are firm, dependable and available to meet peak demands.

Assessing "Willingness to Pay" for Decommissioning

"Willingness to Pay" is an economics term that denotes what consumers could be willing to pay to achieve a public policy option that suits their economic interests (in this context it is not an expression of public opinion for salmonid protection).[71] Given the two public policy options for the Klamath Hydroelectric Project assessed in KPAAM, it is a measure of what ratepayers might be willing to contribute towards decommissioning. PacifiCorp ratepayers will have to pay either the relicensing costs for Klamath, or the decommissioning and replacement power costs. The status quo condition of very low hydropower costs from Klamath is available only so long as it is allowed to operate in its current state of high environmental damage to salmonid resources. When FERC stops issuing annual license renewals and issues a new license for the Project, new costs will be incurred by ratepayers.

A willingness to pay measure for PacifiCorp ratepayers can be estimated by subtracting replacement power costs from relicensing costs, again for a range of replacement cost forecasts. Because PacifiCorp ratepayers will have to pay either for relicensing or for replacement power; the difference between the two is indicative of their willingness to pay for decommissioning. This is also an estimate of the total net benefits to ratepayers from selecting the least cost option. Public utility commissions take this perspective in their General Rate Case Proceedings as they evaluate the reasonableness of costs incurred by utilities such as PacifiCorp

The estimated decommissioning costs are shown in the first row, which are the sum of dam removal, lost book value, and interim mitigation measures (currently set at $0). Again, using PacifiCorp's 2005 forecast for replacement power (highlighted), Table 4-5 indicates that ratepayers could save up to $195 million over a 30-year period that could be paid toward dam removal if the Klamath project is decommissioned rather than relicensed.

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71 This is a cost-effectiveness analysis comparing between two policy options focused on providing the maximum ratepayer benefits—it is not a full benefit-cost analysis. However, the principles of benefit-cost and economic welfare analyses apply here. See for example, Hal R. Varian, *Microeconomic Analysis*, Third ed. (New York: W.W. Norton & Co., 1992), pp. 222-232; and Edward M. Gramlich, *Benefit-Cost Analysis of Government Programs* (Englewood Cliffs, N.J.: Prentice-Hall, Inc., 1981).

Table 4-5: PacifiCorp Ratepayers Willingness to Pay for Decommissioning (2005$ Millions)				
		Low	**Midline**	**High**
Decommissioning Costs		$77	$94	$110
Replacement Power Cost Forecast	***$/MWh***			
US DOI	*$35.59*	$156	$286	$396
US DOI-PacifiCorp+EIA	*$47.15*	$131	$261	$371
NWPPC 5th Power Plan	*$51.56*	$122	$252	$362
Oregon DOE	*$59.76*	$105	$235	$345
PacifiCorp 2005	*$78.98*	$65	$195	$305
CPUC MPR	*$79.73*	$63	$193	$303

It is clear from the table that estimated decommissioning costs are generally below estimated willingness to pay estimates, across the range of replacement cost forecast. This table shows that ratepayers will benefit more from decommissioning than from relicensing under the set of assumptions used in this run of the KPAAM. The various public utilities commissions could be expected to look at this cost range and determine what amount of relicensing costs are allowed into ratebase relative to the alternative of decommissioning instead. The lower cost replacement power forecasts suggests that decommissioning costs need to be nearly three times higher than initial estimates before ratepayers are indifferent, economically, between relicensing and decommissioning. This finding is preliminary and does not include interim mitigation costs for the decommissioning scenario, so the current estimate of decommissioning costs (ranging from $77 to $110 million in NPV) likely will be higher once mitigation costs are included.

Interpretation and Conclusions

The Klamath Project is small compared to the total power needs of PacifiCorp's customers and to the systems-level scale of new generation needed to meet load, reserve margins and transmission system reliability in the utility’s service territory. In its 2003 *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, staff from the Energy Commission concluded that decommissioning some or all of the Klamath facility was a feasible alternative that should be further examined during relicensing. Given the size of the PacifiCorp system, the relatively large amount of capacity and energy already procured (approximately 22 percent), and the amount of additional capacity and energy needed to meet projected load growth, the report also concluded that loss of the Klamath Hydroelectric Project “would not have a demonstrably significant effect on resource adequacy.”

PacifiCorp's energy planners are also assessing how to replace the energy and capacity from the Klamath Project. The August update to its Preferred Portfolio in the *2006 Integrated Resource Plan* identifies "Replace Klamath hydro units with alternative resources." According to PacifiCorp's Final License Application to FERC, local transmission improvements totaling $5.6 million could allow replacement power to be brought in from the grid. Since 1999 PacifiCorp has decided to remove dams totaling 28.5 MW of capacity at four other FERC-licensed projects rather than retrofit existing facilities as a condition of operating under new licenses. In September 2006 PacifiCorp began removal of the 7.5 MW Cove Dam in Idaho.

Power plants are routinely retired when they are no longer economically competitive or environmentally compliant (e.g., a coal-fired generator may be retired if there is a new requirement for a scrubber, and replacing the generation may be less costly than retrofitting the old plant), or when the equipment has outlived its design life (natural gas, nuclear, wind turbines, etc). For example, in the state of California 3,810 MW has been retired for various reasons since 2001.[72] The Klamath Project is relatively small compared to the type of large thermal plants that have been retired in California.

From a review of the PacifiCorp filings with FERC and with the Public Utility Commissions in Oregon and California, it is apparent that the Klamath Hydro Project primarily serves as a low cost energy resource with little firm capacity or peaking dispatch flexibility. This type of replacement energy is readily available from other PacifiCorp generating resources and from the grid.

The Klamath Hydro Project is a low cost energy resource because it does not have modern mitigation measures to ensure fish passage or water quality. As shown in KPAAM, adding these measures would increase production costs by $30 to $61 per MWh and would total $230 to $470 million over 30 years. However, the 169 MW Klamath Project would still be an intermittent, low capacity, inflexible energy resource with 23 percent lower production levels. Decommissioning the project and procuring 30 year's worth of replacement electricity for PacifiCorp's customers would cost $242 to $275 million – and would be $101 million cheaper under the midline cost estimates than relicensing the project – if PacifiCorp's own estimate for replacement power is used. In comparison, a new 500 MW natural gas-fired combined cycle power plant that meets all State of California air quality standards can be constructed for $350 million to $400 million. Facilities such as these provide firm capacity and peaking dispatch flexibility for nearly all of their nameplate capacity throughout their design life, and would be three times larger than the Klamath Project.

PacifiCorp's ratepayers in six states will have to pay either to relicense the project and install substantial mitigation measures, or to decommission the project and procure replacement power elsewhere. The status quo operations will continue only until a regulatory decision is made. This application of KPAAM demonstrates that decommissioning the Klamath Hydro Project would create net economic benefits for

[72] California Energy Commission, http://www.energy.ca.gov/electricity/inactive_plants.html, October 31, 2006.

PacifiCorp's ratepayers. Decommissioning also creates the potential for restoring salmon runs to one of the most important remaining salmon rivers on the West Coast.

APPENDIX A

USER'S GUIDE FOR KLAMATH PROJECT ALTERNATIVES ANALYSIS MODEL (KPAAM)

This appendix describes the Klamath Project Alternatives Analysis Model (KPAAM) by providing an overview and detailing key model components. KPAAM was developed using Microsoft Excel 2000 to compare economic and financial costs of Klamath Dam relicensing and decommissioning using a variety of assumptions about the magnitude and timing of four cost categories: replacement power production, dam removal, environmental mitigations, and remaining undepreciated capital investments.

Model Overview

The KPAAM model contains 21 linked worksheets. The worksheet tabs and associated information sources are listed in Table A-1 by cost category. Table A-2 shows what data and cost/revenue calculations are contained in each worksheet tab.

Modeling input data and assumptions are provided by state and federal agencies, as well as PacifiCorp filings with the Oregon PUC and California Energy Commission. Values used in the model are converted to constant 2005 dollars (2005$). Where original values are not in 2005$, they are adjusted using the 2004 GDP Implicit Price Deflator, as reported in the *GDP Deflator* tab in the KPAAM. Costs and revenues are defined for each category, with future values "discounted" to estimate a net present value (NPV). Discount rates used for NPV calculations are shown below in Table A-3: User Selected Scenario Parameters, which reproduces the *Scenario Summary* tab. In the base case presented here, the Weighted Average Cost of Capital (WACC), which is the rate of return paid by ratepayers to PacifiCorp on investment, is assumed to be 9.08% and the inflation rate is set at 2.8%, yielding a real discount rate of 6.27%;[73] however, these values are adjustable within the model.

A two-color scheme is used to indicate editable and locked cells to guide the user in adjusting input parameter values, as well as to indicate positive or negative net present values. Inputs and assumptions can be controlled from the *Scenario Summary* tab. On that worksheet, user-controlled cells are yellow and fixed cells are red. The *Summary* and *Results Sum Matrix* tabs present comparisons of net present values of cost categories for decommissioning and relicensing. Color coding is used to indicate the "take home" finding: Red cells indicate that the net present value of decommissioning costs are greater than relicensing costs, so it is cheaper to relicense the Klamath power complex. Green cells indicate that decommissioning costs are lower than relicensing costs, so it is cheaper to remove the Klamath dam complex and to replace the lost hydroelectricity while avoiding environmental

[73] Based on PacifiCorp filing UE-179 before the Oregon Public Utilities Commission; the WACC of 9.08% is derived from 46.2% (debt) * 6.37% (interest) + 1% (preferred) * 6.54% (return) + 52.8% (common) * 11.5% (equity return). In PacifiCorp 2005 GRC A.05-11-022, the WACC = 9.25%.

mitigation costs. Within individual cost category worksheets, green and red cells mean positive and negative net present value, respectively.

Table A-1
Summary of KPPAM Cost Categories and Model Structure

Cost Category	Information Sources	Tab Reference in Excel Workbook
Replacement Power	• U.S. Bureau of Reclamation provided flow and generation cases, hydrologic histories and forecasts based on CALSIM II modeling. • USBR also provided historic power revenue data described by water year type (e.g., wet, dry). • Replacement power cost and gas price forecasts are from published and agency sources.	• Replacement power cost o PowerCostCalc o Power Cases o ReplCostAls o ReplCostGraph o Monthly & Wghtd Prices o GasPricesAlts o GasPricesGraph • Hydrology o Flow Cases o BLMHist & BLM2012 o Current Hist & Current 2012 o Hydrology
Decommissioning	• Decommissioning costs are based on estimated from PacifiCorp and California Energy Commission.	• DecomCostCalc
Lost Depreciation	• PacifiCorp FERC Project 2082 - Klamath Cost, 2004 FERC Form 1 (May 2005)	• Form 1 Costs
Mitigation	• PacifiCorp, US Bureau of Land Management, and U.S. Fish and Wildlife Service.	• MitCostCalc

Table A-2
KPPAM Components and Calculations

Tab Name	Cost Calculations and Information
Summary and Results Sum Matrix	Net Present Value comparisons of relicensing and decommissioning low, mid and high-ranges for several replacement cost forecast scenarios.
Scenario Summary	Editable assumptions about financing terms and the timings, costs and uncertainties of mitigation and decommissioning costs.
DecomCostCalc	Dam Removal costs and timings.
MitCostCalc	List of Mitigation Measures costs and timings for relicensing
PowerCostCalc	Replacement power production costs calculations based on power production changes in the Power Cases tab.
Power Cases	Replacement power production changes from historic to current, and from current to decommissioning or relicensing.
Form 1 Costs	Undepreciated Asset Costs for Decommissioning; Marginal cost of producing power at each Klamath development
Monthly & Wghtd Prices	Price premium calculations for peak power compared with offpeak power.
ReplCostAls and ReplCostGraph	Collection of replacement power cost forecasts; conversion of cost forecasts to levelized power cost.
GasPricesAlts and GasPricesGraph	Collection of natural gas price forecasts
Flow Cases, BLM Hist, BLM 2012, Current Hist and Current 2012	Historic, current and future flow conditions for relicensing and decommissioning based on CALSIM modeling by U.S. Bureau Of Reclamation.
Hydrology	44 years of net surface water inflow at Upper Klamath Lake used to calculate probabilities of dry, below average, average, above average and wet water years.
Compare Annual Peak and Peak/Offpeak Plots	Compare peak and off-peak power production by water year type.
GDP Deflator	2004 Gross Domestic Product implicit price deflator.

Scenario Summaries

Users may create “scenarios” that are composites of values chosen for influential parameters. Table A-3 shows the model parameter and value used to generate the results presented in this report. In the spreadsheet, user-controlled cells containing scenario assumptions are yellow and fixed cells are red. Parameters to be manipulated include:

- starting and ending years of the study period
- discount rate for calculating net present values

- terms and rates for financing capital costs
- schedule and costs for decommissioning
- environmental impact mitigation costs
- uncertainty adjustment factors that are used to develop low, mid and high estimate ranges,
- cost estimate multipliers to generate conservative values that account for incomplete and uncertain information about costs.

Financing terms (i.e., time period of the loan and number of loan repayments) and rates (i.e., interest rate to be paid on the loan) are used to discount future costs and revenues using the following standard equation:

$$\text{Present Value} = \frac{\text{Future Value}}{(1 + rate)^{time}}$$

Costs assumed to be financed include infrastructure investments, dam decommissioning, and mitigation measure costs, and the property tax rates.

Model users may also choose how uncertainty is represented in outputs. Decommissioning and mitigation costs have two treatments for uncertainty. An uncertainty adjustment factor calculates the low and high ends of cost range estimates, and is set at 30 percent for both decommissioning and mitigation costs. A cost estimate multiplier may also be adjusted to raise or lower the midline estimate from which high and low range values are calculated.

There are placeholders for changing mitigation costs and schedule, but only one scenario is developed for this version of the model based on estimates provided by PacifiCorp and public agencies. The costs and timing of mitigation measures are discussed in the Methods by Cost Category – Mitigation section.

Another set of important assumptions pertain to the estimate of replacement power costs. A key price adjustment represents the difference in the daily timing of peak power production relative to historic and current production. That is, the model accounts for the shift in peak power generation, and the associated change in economic value from that shift beyond the loss of generation from bypass flows or other generation quantity reductions.

Table A-3
User Selected Scenario Parameters

Start Year		2008
Study Period (Years)		30
Ending Year		2048
Financing		
	Weighted Average Cost of Capital (WACC) (%)	9.08%
	Inflation Rate (%)	2.8%
	Real Disc. Rate (%)	6.27%
	License Term = Finance Term for Infrastructure	30
	Property Tax Rate	1.3%
	Finance Term for Decommissioning	30
	Finance Term for Mitigations	30
Replacement Power Costs		
	Nonfirm Power Discount	0%
	Power Price Premium from Peaking: Current conditions	101%
	Power Price Premium from Peaking: Relicensed conditions	97%
Mitigation		
	Initial Cost Estimate	1
	Schedule	1
	Uncertainty Adjustment	30%
	Cost Estimate Multiplier	100%

Methods by Cost Category

Mitigation

Infrastructure construction, retimed water flows, and other actions to mitigate for impacts under the relicensing case are included on the tab, *MitCostCalc*. These costs are estimated using a list of mitigations provided by the U.S. Department of the Interior based on filings by PacifiCorp, federal and state resource management agencies mandated and recommended under the Federal Power Act. Costs are organized by dam development for three categories:

- Fish Passage Conditions for full volitional upstream and downstream passage past four power dams, including spillway and tailrace improvements, and hatchery operations.
- Non-fish Passage Conditions to support riparian restoration, terrestrial biology, recreation, and cultural resources.
- Water Quality Conditions to comply with water quality standards per section 401(e) of the Clean Water Act, including installation of oxygen diffusers and temperature control measures at four dams.

The mitigation measures are described by their priority, legal reference, timing and cost for capital, operations and management. From the composite case, costs were recapitulated per the three mitigation cost categories, and a schedule of cost timing was developed from which to calculate present values.

With very little additional information about the uncertainties associated with individual estimates, a simple high-low range using a +/- 30 percent uncertainty factor is added to cost estimates. Users may adjust the uncertainty factor in the *Scenario Summary* tab.[74]

No cost estimates are available for mitigation costs in the decommissioning scenario, but they should be included in future improvements to the model.

Remaining Undepreciated Investment

The value of the Klamath complex is a depreciable asset, so at decommissioning the unrecovered "book value" investment becomes a cost. Book value means recoverable cash capital costs owed to shareholders. In the model, the *Form 1 Costs* tab shows remaining undepreciated values for JC Boyle, Copco I & II and Iron Gate dam infrastructure. Values used in KPAAM are in need of adjustment to conform with PacifiCorp data for remaining value in 2013.

Decommissioning

Two cost scenarios for removing dams are developed based on agency and PacifiCorp estimates. In addition, four decommissioning schedules are built into the model though only the Proposed Settlement schedule is used for this version of modeling results. As discussed in the Model Overview section, the removal schedule and cost assumptions, including financing terms, may be manipulated on the *ScenarioSummary* tab.

The model assumes current license conditions until removal; however, interim conditions may be proposed that are not yet depicted in the model. Cost estimates for decommissioning remain uncertain and likely need to be updated. A study is underway by the Coastal Conservancy,[75] and it is possible to run other scenarios in terms of decommissioning schedule and costs.

Calculation of the net present value of decommissioning costs is performed on the *DecomCostCalc* tab. The user has two mechanisms for treating endogenous uncertainty pertaining to hydrology and decommissioning costs. The power production uncertainty range describes the extent of deviation from an average rainfall year. For decommissioning costs, the user can select an uncertainty factor akin to the factor used for mitigation costs that is currently set at 30 percent. For use

[74] In creating these high-low scenarios, no statement of probability is made as it has not been examined systematically. Analytical analysis of uncertainty is not tractable due to algorithm complexity, but Monte Carlo or other "brute force" methods may be used for assessment of the probability of outcomes.

[75] This study is discussed in the main report.

in sensitivity analyses, a cost estimate multiplier is built into the model but is currently set at 1 (i.e., 100 percent, or no multiplication). Furthermore, the decommissioning schedule may be adjusted on the *Scenario Summary* as shown in Table A-3.

Replacement Power

Replacement power costs are estimated for both mitigated relicensing and decommissioning scenarios by multiplying levelized replacement power costs ($/MWh) by lost hydroelectric power production (MWh) for each year of the study period.

The decommissioning case includes several years of “as usual” power production before the dams are removed according to the schedule in the *ScenarioSummary* tab; that is, the difference between the assumed date for relicensing (2008 in this case) and the scheduled date of dam removal. Water flows in the decommissioning case are assumed to exceed those under relicensing conditions, so the decommissioning case enjoys net revenues equal to replacement power costs minus the costs of power generation at each Klamath development. As shown on the *Form 1 Costs* tab, the marginal cost of power generation is calculated by dividing operating expenses by power produced (as shown on the *Flow Cases* tab.)

Replacement power cost scenarios are summarized in the *PowerCostCalc* tab, which links to several tabs for calculating water flow and power generation changes for each scenario. The user may also view several forecasts for replacement power costs on the *ReplCostAlts* tab. The user may add other forecasts to this tab and add them to the graphics that display results, or replace the existing forecasts with alternative forecasts.

- US Department of the Interior (DOI) – Current power replacement cost from range of sources: mid-range of estimates that include long-term forecasts and current prices.
- Northwest Power Planning Council (NWPPC) - Wholesale Mid Columbia spot market for mix of resources in PNW: may underestimate new resource cost.
- DOI-PacifiCorp+EIA – Created by DOI from PacifiCorp 2003 marginal cost filings with the Energy Information Administrations Annual Energy Outlook 2006 gas price forecast: Marginal cost based on combined-cycle gas turbine plant.
- Oregon Department of Energy – based on a 50% biomass generation and 50% demand side management (DSM) with specific resource replacement.
- PacifiCorp – 2005 Integrated Resource Plan: long run blended portfolio costs. Higher than its contemporary Oregon Public Utilities Commission (OPUC) rate case filing in U179.
- California Public Utilities Commission (CPUC) Market Price Referent – a combined-cycle gas turbine plant on the margin 88% of year, used to benchmark renewable generation bids: may overestimate long-run new resource costs

Forecasted costs are provided in nominal dollars, but are inflated to 2005$ and levelized over the study period, which may be defined by the user and is currently set at 40 years, 2008 through 2048. For reference, levelized power cost forecasts are displayed in the *Summary* and *Results Sum Matrix* tabs.

In depicting differences between historic, current and future power production by the Klamath development, it is important to recognize shifts in the timing of production. The KPAAM model calculates the differences in peak and nonpeak power production value relative to historic production for both the current operating conditions and relicensing. The current condition value is set at 101%, meaning that the total value of generation given the change in the power profile is 1% higher under current (i.e., 2012 BO) conditions compared with historic operations. Relicensing peak power is set at 97% of current conditions to reflect the assumption that relicensing rules that constrain the timing of peak power generation will reduce the value of power by 3%. The 3% adjustment represents a change in the value of all hydroelectric power produced by the Klamath project and is independent of changes in total generation.

A second adjustment reflects that “firmness” of replacement power relative to Klamath development power. Price forecasts for firm power may not match the intermittent nature of Klamath power production. The Klamath development relies on water flows, so the nameplate production capacity of 169 MW is not assured in dry water years. When water is plentiful in winter, firm capacity is estimated at 92 MW. Replacement power cost forecasts generally assume firm power; for example, a natural gas-fueled power plant is not subject to hydrologic variability, so the power can be considered “firm.” Power from the Klamath development in summer is not firm since it may be minimal during droughts. The *Scenario Summary* tab includes an editable parameter to depict the replacement cost “discount” for replacement power that is nonfirm, though the discount rate is current set at 0% (i.e., no discount).

Natural gas prices are embodied in replacement power production forecasts that typically assume that large-scale combined cycle natural gas-fueled power plants will be the technology of choice. KPAAM provides several natural gas price forecasts that, like replacement power forecasts, show a wide range that indicates considerable uncertainty. KPAAM gas price forecasts are from several published sources:

- Energy Information Administration (EIA) of the U.S. Department of Energy, Annual Energy Outlook 2006, Early Release Date: December 12, 2005.
- Northwest Power and Conservation Council (NPCC), 5th Power Plan, FuelMod04. April 20, 2002.
- California Energy Commission, Natural Gas Price Forecast. 2005-06-14_PGenP.xls. July 7, 2005.
- NYMEX Futures Prices from Dec 2005 and June 2006
- Two forecasts from PacifiCorp filed with the CPUC for avoided natural gas prices and marginal costs.

Presentation of Results

Modeling results calculate the Net Present Value of costs over a period selected by the user on the *ScenarioSummary* tab. Thirty years was used in the case presented here. Summary results compare decommissioning against a relicensing base case, thereby showing the net cost to PacifiCorp ratepayers for decommissioning.

The *Summary* and *ResultsSumMatrix* tabs contain summary results presented using several metrics and formats. The results are color-coded: Red values indicate it is cheaper to relicense, whereas green values indicate that it is cheaper to decommission. Initial comparison results are shown in Table A-4. Bar charts compare total decommissioning and relicensing costs based on the scenarios and assumptions on the *Scenario Summary* tab. The *Summary* tab shows the comparison in terms of levelized power cost, which is the net present value of the power revenues divided by the net present value of the energy generation over the planning horizon (e.g., 30 years in this case.)

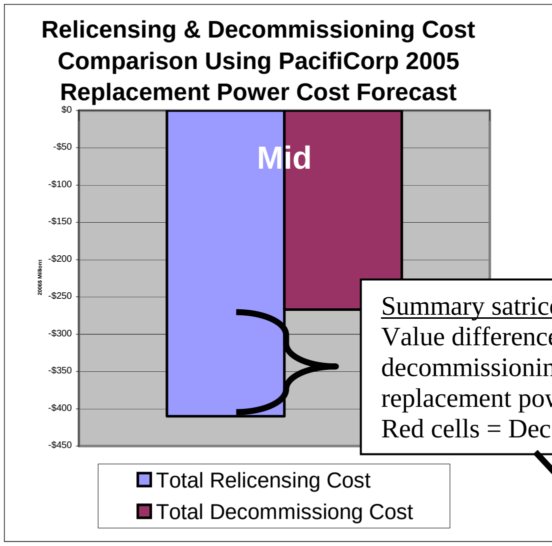
The comparison metrics in Table A-4 show the results of subtracting the costs of decommissioning from the costs of relicensing. Mathematically, the equation is:

+ (Relicensing mitigation costs + Ongoing O&M costs)
- (Dam removal costs + Remaining book value + Replacement power costs)
= Net Present Value Relicensing minus Decommissioning

The method for comparing relicensing and decommissioning is shown graphically in Figure A-1, with an arrow showing the corresponding summary statistic in Table A-4. These graphic are exemplary, not comprehensive; they compare mid-range results using replacement power cost forecasts provided by PacifiCorp in 2005. The arrow show how the Figure A-1 comparison produces just one value ($143.1 million) amongst a sets of results for low, mid and high-ranges, as well as different replacement power cost forecasts.

Where the net value is negative, decommissioning is more costly than relicensing. Also included in the summary results is a “Break Even” calculation that shows, in levelized dollars per MWh, the cost of replacement power that would make decommissioning costs equal to relicensing costs.

Figure A-1: Summary Matrices Calculation Method



Summary satrices show the Net Present Value differences between relicensing and decommissioning costs for a range of replacement power cost assumptions.
Red cells = Decommissioning is least cost

Table A-4
NPV of Relicensing Minus Decommissioning plus Replacement Power Costs by Replacement Power Cost Scenario (2006$ Millions)

Replacement Power Cost Forecast	$/MWh	Low	Midline	High
US DOI	$35.59	$102.8	$233.9	$335.0
US DOI-PacifiCorp+EIA	$47.15	$78.6	$209.7	$310.8
NWPPC 5th Power Plan	$51.56	$69.4	$200.5	$301.5
Oregon DOE	$59.76	$52.2	$183.3	$284.4
PacifiCorp 2005	$78.98	$12.0	$143.1	$244.2
CPUC MPR	$79.73	$10.5	$141.5	$242.6
Break Even	$/MWh	$100.81	$over 160.33	$232.78

Uncertainty and Sensitivity Analyses

Two types of uncertainty influence the reliability of modeling results: exogenous and endogenous.[76] Exogenous uncertainty pertains to events or processes that are predictably random (i.e., stochastic) and thus quantifiable after observation. Endogenous uncertainty pertains to "fork in the road" events that cannot be predicted and are thus not represented explicitly in the modeling construct or range of scenarios modeled. There is little we can do to eliminate either source of uncertainty, but both are represented in our cost model.

Two approaches are used for addressing exogenous uncertainties: probabilistic description and development of input parameter ranges (i.e., scenarios). The natural variability of monthly water flows is represented using a probability distribution based on 44 years of water flow records.[77] A second approach for managing exogenous uncertainty is to provide a range of values – scenarios – for influential input parameters, most notably replacement power cost forecasts. Selecting alternative power price forecasts, while holding all other assumptions constant, is an example of a local sensitivity analysis. Initial modeling results present findings for five different replacement power price forecasts, thereby providing local sensitivity results for this significant input parameter.

Exogenous uncertainty is represented by composite modeling scenarios where several input parameters are adjusted within their ranges of uncertainty. This technique of perturbing several inputs simultaneously is a form of global sensitivity assessment. To the extent that the ranges capture exogenous uncertainties (and they certainly do not capture all), then global uncertainty analysis will shed light on the significance of exogenous uncertainty. Nonetheless, a new war, for example, may have dramatic impacts on natural gas prices not depicted in the range implicit in power price forecasts.

Additional Local Sensitivity Analyses

Based on responses to this study and other inputs from interested parties, additional sensitivity analyses can be performed to inform policy decisions. Such analyses can help to focus future efforts at uncertainty reduction by identifying influential model parameters or assumptions. The degree of influence (i.e., sensitivity coefficients) combined with the extent of uncertainty (i.e., possible range of values) associated with individual parameters and assumptions indicates which inputs require further specification to improve confidence in modeling results.

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[76] Modeling uncertainty has been categorized in several different ways. It is helpful to consider four uncertainty concerns in any modeling effort:

- Uncertainties in model formulation
- Uncertainties in input data
- Variability
- Use of modeling results in decision-making.

Endogenous and exogenous uncertainties pertain to each of these four categories, though no attempt is made herein to address the fourth uncertainty.

77 See *Hydrology* tab in Cost Model workbook.

One important aspect is to evaluate the sensitivity of results to total mitigation and decommissioning costs, since both are quite uncertain. As well, slight changes in the timing of events, such as delaying decommissioning by one or five years, may be of particular interest to policy-makers. Key modeling parameters that could be tested using sensitivity analyses include the weighted average cost of capital, inflation rate, real discount rate, and payback period for borrowed capital. Another exogenous uncertainty not captured in the current model is future hydrology. Though the hydrology is treated correctly in a probabilistic manner, all probabilities are based on past hydrology; yet, it remains likely that future hydrology will differ from historic observations due to several factors including global climate change.[78]

Additional Global Sensitivity Analyses

Systematic formal sensitivity analyses can yield deeper understanding of model behavior and information for use in probabilistic risk assessment. Though initial results provide an indication of the range of possible outcomes, they do not provide information needed to estimate the probabilities of outcomes. Such probabilistic assessment can be conducted using analytic or "brute force" sensitivity analyses. Increased computing power has allowed for increasing the use of brute force methods of probabilistic assessment (e.g., using Monte Carlo simulation) and Bayesian techniques (e.g., updating initial uncertainty descriptions once new information becomes available). Analytical uncertainty propagation is not tractable due to the complexity of model formulation (notably the exponential functions used for net present value calculations), so brute force is the only option. Monte Carlo analyses create hundreds or thousands of outcomes by randomly and simultaneously selecting from within the range of possibilities of several input parameters. Repeating the Monte Carlo process several hundred or thousand times will produce a distribution of outcomes from which probabilistic summaries become possible.

Another related option is the use of "robust decision making" (RDM) in which computers and expert judgment are used to search for the "least worse" outcomes along promising policy-choice paths.[79] Decision theoricians agree that when there is considerable uncertainty, probabilistic risk assessment and management is preferable to decision-making using deterministic models and that it is valuable to seek uncertainty information explicitly.

The RDM analysis proceeds to take various policy proposals, identify their significant vulnerabilities, assess if those vulnerabilities might be mitigated effectively, characterize deep uncertainties and likely trade-offs, and then select the most likely policy options that best meet the overall objectives given the ranges of uncertainty. Stakeholders provide policy alternatives and hedging strategies. The analyst identifies the deep uncertainties and runs the model to assess vulnerabilities and trade-offs. Decision makers are kept appraised of the policy proposals and intermediate results, and in the end, are provided with a portfolio of choices in which

[78] This possibility can be evaluated by adjusting the Power Production Uncertainty Range on the *Scenario Summary* tab.
[79] Robert J. Lempert et al., "A General, Analytic Method for Generating Robust Strategies and Narrative Scenarios," *Management Science* 52, no. 2 (2006): 514-528.

trade-offs are clearly identified. The final presentation would show the multi-dimensionality of the problem as well as the gradation across choices.

APPENDIX B

Mitigation Cost Summary for the Relicensing Condition (Tabular version of the mitcostcalc tab from KPAAM)

Appendix B: Mitigation Cost Summary for the Relicensing Condition

Category	Relicensing Case Mitigation Measure	Agency Mandatory	PacifiCorp Proposed	Agency Recommended	Implementation/ Construction Year	Capital ($ thousands)	NPV Capital($ thousands)	O&M ($ thousands)	NPV O&M ($ thousands)	Source
J.C. Boyle										
Mitigation: Aquatic	JC Boyle Bypass-Iron Gate		1		1	461	$385.9	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Gravel Augmentation Monitoring		1		1	0		8.9	$145.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	JC Boyle Fish Ladder Upgrades		1		1	500	$418.5	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	JC Boyle Bypass Gage		1		1	60	$50.2	10.0	$163.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	J.C. Boyle Bypass	1			2	2,084	$1,644.1	5.6	$86.4	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	J.C. Boyle Dam Upstream Fishway	1			4	15,010	$10,517.4	45.0	$613.9	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	J.C. Boyle Dam Downstream Fishway	1			4	39,402	$27,608.7	56.2	$767.4	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	J.C. Boyle Spillway	1			5	4,170	$2,753.7	145.0	$1,864.5	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	J.C. Boyle Tailrace Barrier	1			5	10,686	$7,056.6	28.1	$361.6	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	JC Boyle Synchronous Bypass Valve		1		1	6,161	$5,157.2	5.4	$88.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	4 - River Corridor Management	1					$0.0		$0.0	
Administrative	1 - Activities On or Affecting Bureau of Land Management-Administered Lands	1					$0.0		$0.0	
Administrative	9 - Reservation of Section 4(e) Authorities	1					$0.0		$0.0	
Decommisioning	2 - Consultation with the Bureau of Land Management	1			1			470.0	$7,660.7	Staff
Mitgation: Cultural	5 - Cultural Resources Inventory and Management	1					$0.0		$0.0	
Mitigation: Cultural	Protect Cultural Sites		1		1	4,800	$4,018.0	105.0	$1,711.4	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Pioneer Crossing Recreation Area (existing) pg 8		1		1	254	$212.6	5.0	$81.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Dispersed Sites and Use Ares (exsting) pg 8		1		1	60	$50.2	2.0	$32.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Upper J.C. Boyle Reservoir Boater Access (potential) pg 9		1		1	90	$75.3	0.5	$8.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Stateline Take-out (existing)		1		1	90	$75.3	2.0	$32.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Fishing Access Sites 1-6 (existing) pg 10		1		1	300	$251.1	2.0	$32.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Dispersed Sites and Use Ares (exsting) pg 10		1		1	0		0.5	$8.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Boyle Bluffs Recreation Area (potential-if land can be aquired) pg 9		1		5	1,089	$719.1	1.0	$12.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	J.C.Boyle Dam River Access and J.C. Boyle Powerhouse River Access (potential) pg 11		1		5	80	$52.8	0.5	$6.4	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	JC Boyle Reservoir Loop Trail (potential) pg 9		1		10	100	$49.1	0.5	$4.8	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	J.C.Boyle Powerhouse River Access with New Trail to Spring Island Boater Access (potential) pg 11		1		10	127	$62.4	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	6 - Recreation and Aesthetic Resources Management	1					$0.0		$0.0	
Mitigation: Terrestrial	Add one large animal crossing and seven small animal crossings at suitable locations along the J.C. Boyle canal		1		3	300	$223.0	1.8	$26.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	3 - Roads Inventory Analysis and Roads Management	1					$0.0		$0.0	
Mitigation: Terrestrial	7 - Vegetation Resources Management Plan	1					$0.0		$0.0	
Mitigation: Terrestrial	8 - Mitigation for Impacts to Wildlife and Wildlife Habitat	1					$0.0		$0.0	

Appendix B: Mitigation Cost Summary for the Relicensing Condition

Category	Relicensing Case Mitigation Measure	Agency Mandatory	PacifiCorp Proposed	Agency Recommended	Implementation/ Construction Year	Capital ($ thousands)	NPV Capital($ thousands)	O&M ($ thousands)	NPV O&M ($ thousands)	Source
Copco 1										
Mitigation: Aquatic	Copco Ranch Irrigation Upgrade		1		1	540	$452.0	8.3	$135.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Copco 1 Dam Upstream Fishway	1			6	29,915	$18,617.7	45.0	$545.3	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 1 Dam Downstream Fishway	1			6	39,402	$24,522.0	56.2	$681.6	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 1 Spillway	1			6	4,170	$2,595.2	11.2	$136.3	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 1 Tailrace Barrier	1			8	12,253	$6,773.1	28.1	$302.7	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Cultural	Protect Cultural Sites		1		1	900	$753.4	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Mallard Cove Recreation Area (existing) pg 11		1		1	225	$188.3	6.0	$97.8	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Copco Cove Recreation Area (existing) pg 12		1		1	54	$45.2	2.0	$32.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Dispersed Sites and Use Areas (existing) pg 12		1		1			0.2	$3.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Operations	Runner Replacement		1		3		$0.0		$0.0	PC FLA Table H3.4-1
Operations	Generator Overhaul		1		16		$0.0		$0.0	PC FLA Table H3.4-2
Operations	Generator Overhaul		1		17		$0.0		$0.0	PC FLA Table H3.4-4
Copco 2										
Mitigation: Aquatic	Copco #2 Bypass Flow Gate Improvements		1		1	75	$62.8	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Copco 2 Bypass Channel Barrier/Impediment Modification	1			2	208	$164.1	5.6	$86.4	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 2 Dam Upstream Fishway	1			6	6,295	$3,917.7	45.0	$545.3	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 2 Dam Downstream Fishway	1			6	36,254	$22,562.8	56.2	$681.6	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 2 Spillway	1			6	416	$258.9	5.6	$68.2	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Copco 2 Tailrace Barrier	1			8	11,392	$6,297.2	28.1	$302.7	PC 4/22/06 CH2MHill Cost Estimates
Operations	Turbine Replacement		1		2		$0.0		$0.0	PC FLA Table H3.4-3
Mitigation: Water Quality	Temperature Control Device - Copco	1			1	30,800	$25,781.9		$0.0	PC 8/1/05 Conceptual Design and Preliminary Screening of Temperature Control Alternatives
Fall Creek										
Mitigation: Aquatic	Spring Creek Parshall Flume		1		1	45	$37.7	2.4	$39.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Fall Creek Upstream Fishway	1			3	104	$77.3	16.9	$244.3	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Fall Creek Downstream Fishway	1			3	357	$265.3	28.1	$407.1	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Fall Creek Tailrace Barrier	1			5	177	$116.9	16.9	$217.0	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Spring Creek Upstream Fishway		1		3	312	$232.0	16.9	$244.3	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Spring Creek Downstream Fishway		1		3	349	$259.5	28.1	$407.1	PC 4/22/06 CH2MHill Cost Estimates
Operations	Turbine Replacement		1		17		$0.0		$0.0	PC FLA Table H3.4-5
Iron Gate										
Mitigation: Aquatic	Fish Tagging		1		1	795	$665.5	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4

Appendix B: Mitigation Cost Summary for the Relicensing Condition

Category	Relicensing Case Mitigation Measure	Agency Mandatory	PacifiCorp Proposed	Agency Recommended	Implementation/ Construction Year	Capital ($ thousands)	NPV Capital($ thousands)	O&M ($ thousands)	NPV O&M ($ thousands)	Source
Mitigation: Aquatic	Tagging Labor		1		1	0		19.2	$312.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Tagging Equipment		1		1	0		14.6	$238.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Tag Materials		1		1	0		76.7	$1,250.2	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Fish Hatchery Minor Upgrades		1		1	0		100.0	$1,629.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-4
Mitigation: Aquatic	Iron Gate Dam Upstream Fishway	1			5	36,608	$24,174.6	157.5	$2,025.0	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Iron Gate DamDownstream Fishway	1			5	25,424	$16,789.1	56.2	$723.2	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Iron Gate Spillway	1			5	1,042	$688.1	11.2	$144.6	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Iron Gate Hatchery Operations			1	1	1,707	$1,428.9	474.6	$7,735.7	FERC DEIS 9/25/06
Mitigation: Cultural	Protect Cultural Sites		1		1	744	$622.8	5.0	$81.5	PC 7/21/04 Response to Deficiency Notice6
Mitigation: Recreation	Fall Creek Recreation Area (existing) pg 12		1		1	150	$125.6	5.0	$81.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Juniper Point Recreation Area (existing) pg 15		1		1	168	$140.6	5.0	$81.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Dispersed Sites and Use Areas (existing) pg 17		1		1	0	$0.0	0.2	$3.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Fall Creek Trail (exisitng) pg 12		1		5	25	$16.5	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Jenny Creek Recreation Area (existing) pg 13		1		5	67	$44.2	1.0	$12.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Camp Creek Recreation Area (existing) pg 14		1		5	3,650	$2,410.3	15.0	$192.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Long Gulch Boat Launch (existing) pg 16		1		5	253	$167.1	4.0	$51.4	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Iron Gate Hatchery Public Use Area (existing) pg 17		1		5	35	$23.1	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Wanaka Springs Recreation Area (existing) pg 13		1		8	205	$113.3	5.0	$53.8	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Mirror Cove Recreation (existing) pg 16		1		8	338	$186.8	10.0	$107.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Overlook Point Recreation Area (existing) pg 16		1		10	90	$44.2	2.0	$19.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Long Gulch to Iron Gate Hatchery Trail (potential)pg 18		1		10	10	$4.9	0.5	$4.8	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Bogus Creek Trail (potential) pg 18		1		10	5	$2.5	0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Recreation	Long Gulch Bluff Recreation Area (existing) pg 17		1		20	3,723	$1,010.4	15.0	$79.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-7
Mitigation: Water Quality	Oxygen Diffuser System Design, permitting, site preparation, mobilization		1		1	248	$207.3		$0.0	PC 9/9/05 AIR 1b
Mitigation: Water Quality	Oxygen Diffuser System Design, Construction, installation, testing		1		2	2,101	$1,657.4		$0.0	PC 9/9/05 AIR 1b
Mitigation: Water Quality	Oxygen Diffuser System Design testing		1		3	8	$5.6		$0.0	PC 9/9/05 AIR 1b
Mitigation: Water Quality	Oxygen Diffuser System Design O&M		1		3		$0.0	255.3	$3,695.7	PC 9/9/05 AIR 1b
Mitigation: Water Quality	Temperature Control Device - Irongate	1			1	32,100	$26,870.1		$0.0	PC 8/1/05 Conceptual Design and Preliminary Screening of Temperature Control Alternatives
Operations	Generator Overhaul		1		11		$0.0		$0.0	PC FLA Table H3.4-6
Other Development										
Administrative	New or Amended Contract	1					$0.0		$0.0	
Administrative	Operating Criteria for Link River and Iron Gate	1					$0.0		$0.0	
Administrative	Operating Criteria for Keno and Iron Gate	1					$0.0		$0.0	

Appendix B: Mitigation Cost Summary for the Relicensing Condition

Category	Relicensing Case Mitigation Measure	Agency Mandatory	PacifiCorp Proposed	Agency Recommended	Implementation/ Construction Year	Capital ($ thousands)	NPV Capital($ thousands)	O&M ($ thousands)	NPV O&M ($ thousands)	Source
Administrative	Area Capacity Curves	1					$0.0		$0.0	
Administrative	Consultation with Reclamation	1					$0.0		$0.0	
Administrative	No Claims	1					$0.0		$0.0	
Administrative	Reservation of Section 4(e) Authorities	1					$0.0		$0.0	
Administrative	Emergency Operations			1			$0.0		$0.0	
Administrative	Cooperative Management Agreement			1			$0.0		$0.0	
Mitigation: Aquatic	Upstream Fishway at Keno Dam	1			3	6,670	$4,959.1	393.7	$5,699.6	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Keno Spillway	1			3	208	$154.6	56.2	$814.2	PC 4/22/06 CH2MHill Cost Estimates
Mitigation: Aquatic	Downstream Fish Passage Program Habitat Protection, Mitigation, and Enhancement Plan			1			$0.0	250.0	$4,323.7	FWS Staff
Mitigation: Aquatic	Upstream Fish Passage Program Habitat Protection, Mitigation, and Enhancement Plan			1			$0.0	250.0	$4,323.7	FWS Staff
Mitigation: Aquatic	Fish Habitat Protection, Mitigation, and Enhancement Plan			1			$0.0	700.0	$12,106.4	FWS Staff
Mitigation: Aquatic	Pacific Lamprey Management Plan and Evaluation			1			$0.0	0.0	$0.0	
Mitigation: Aquatic	Decommissioning Plan for the East Side and West Side Developments			1			$0.0	30.0	$518.8	FWS Staff
Mitigation: Aquatic	Instream Flows everywhere but Boyle (BLM-Boyle)			1			$0.0		$0.0	
Mitigation: Aquatic	Geomorphic and Juvenile Outmigrant Flows			1			$0.0		$0.0	
Mitigation: Aquatic	Gravel Augmentation			1			$0.0		$0.0	
Mitigation: Aquatic	Temperature Control Device Feasibility Study			1			$0.0		$0.0	
Mitigation: Aquatic	Fish Disease Risk Management			1			$0.0		$0.0	
Mitigation: Aquatic	Resident and Anadromous Fish Monitoring			1			$0.0	800.0	$13,835.9	FWS Staff
Mitigation: Aquatic	Aquatic Habitat Monitoring Plan			1			$0.0		$0.0	
Mitigation: Aquatic	Riparian Habitat Management Plan (RHMP)			1			$0.0		$0.0	
Mitigation: Aquatic	Adaptive Management Plan for Federally Listed Suckers			1				200.0	$3,459.0	FWS Staff
Mitigation: Aquatic	Fisheries Technical Subcommittee (FTS)			1			$0.0		$0.0	
Mitigation: Cultural	Historic Properties Management Plan			1			$0.0		$0.0	
Mitigation: Cultural	Mitigate Recreational Impacts on Cultural Resource Sites			1			$0.0		$0.0	
Mitigation: Cultural	Native Plant and Noxious Weed Management			1			$0.0		$0.0	
Mitigation: Cultural	Safety of Dams - Emergency Action Plan			1			$0.0		$0.0	
Mitigation: Cultural	Tribal Participation			1			$0.0		$0.0	
Mitigation: Recreation	Creating and Improving trails in the Link River Reach			1			$0.0		$0.0	
Mitigation: Recreation	Developed Trails from J.C. Boyle Reservoir to Copco Reservoir			1			$0.0		$0.0	
Mitigation: Recreation	Interpretation and Education Program			1			$0.0		$0.0	
Mitigation: Recreation	Recreation Law Enforcement Program			1			$0.0		$0.0	
Mitigation: Terrestrial	Control noxious weeds via Noxious Weeds control Plan		1		1	0		5.8	$94.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5

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Mitigation: Terrestrial	Unique habitat protection		1		1	0		0.1	$1.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Avoid routine maintaince drawdown during spring/summer amphibian and waterfowl breeding seasons		1		1	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Manage riparian habitats within the FERC Project boundary in manner consistent with big games objectives		1		1	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Protect existing riparian habitat and conduct riparian enhancement in other reaches		1		1	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Control noxious weeds via Noxious Weeds		1		1	0		3.0	$48.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Schedule routine maintanance drawdowns outside of the spring/summer breeding seasons		1		1	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Manage riparian and upland habitats within the FERC Project boundary in manner consister with big game objectives		1		1	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Control noxious weeds		1		1	0		5.8	$94.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Continue to support annual surveys for bald eagles nest occupancy and productivity in the Project area		1		1	0		5.0	$81.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Avoidance/awareness of protection measures. Add bat roosting structures near facilities to give bats additional options		1		2	5	$3.9	0.1	$1.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Add bat roosting structures near facilities to give bats additional options		1		2	5	$3.9	0.1	$1.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Add bat roosting structures near facilities to give bats additional options		1		2	5	$3.9	0.1	$1.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Construct backwater areas to establish wetland riparian vegetation and provide habitat for amphibians		1		2	12	$9.5	0.3	$4.6	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	VRMP and WHMP Road Maintanance Plan. Create setback and, if necessary, create erosion control strip to protect wetland near Copco Village		1		2	0	$0.0	0.1	$1.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Avoidance/awareness of protection measures, addition of bat roost structures near facilities		1		2	5	$3.9	0.1	$1.5	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Basking Structures		1		3	5	$3.7	0.1	$1.4	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Protect existing riparian area in FERC boundary		1		3	0	$0.0	0.1	$1.4	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Add logs or rocks in selected areas for turtle basking		1		3	10	$7.4	0.2	$2.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Site will be used for recreation. Coordinate site design. Add native vegetation screening		1		4	10	$7.0	0.2	$2.7	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Develop Road Access Plan to minimize vehicular traffic on non-essential roads		1		5	0		0.0	$0.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5

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Category	Relicensing Case Mitigation Measure	Agency Mandatory	PacifiCorp Proposed	Agency Recommended	Implementation/ Construction Year	Capital ($ thousands)	NPV Capital($ thousands)	O&M ($ thousands)	NPV O&M ($ thousands)	Source
Mitigation: Terrestrial	Develop Road Access Plan and road closures. Roads owned by PacifiCorp that are not necessarily for Project operation or other significant use of private property will be closed. Vehicular access on the closed roads would be limited to administrative use only		1		5	100	$66.0	5.0	$64.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Coordinate with Transmission and Delivery for avoding TEST plant sites and/or protection for TES plant populations in/near rights of way		1		2	7	$5.5	0.8	$12.3	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Establish riparian vegetation to improve distribution. Increase width of existing riparian vegetation by fencing or redirecting human use		1		2	76	$60.0	2.4	$36.9	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Avian Collision and Electrocution Hazards			1			$0.0		$0.0	
Mitigation: Terrestrial	Bald Eagle Protection Measures and Management Plan			1			$0.0		$0.0	
Mitigation: Terrestrial	Fire, Fuels, Forest Health Managing Upland Vegetation			1			$0.0		$0.0	
Mitigation: Terrestrial	Wildlife Habitat Management Plan		1		1	50	$41.9	20.0	$326.0	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Vegetation Resources Management Plan		1		1	60	$50.2	25.9	$422.2	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Develop plan for protecting wetlands near recreational areas		1		3	15	$11.2	0.4	$5.8	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Riparian vegetation enhancement along the klamath river and in shovel creek		1		2	100	$78.9	3.3	$50.7	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Terrestrial	Develop Shortline with trees/shrubs, protect weland sites from livestock or people		1		2	11	$8.7	0.4	$6.1	PC 7/21/04 Response to Deficiency Notice, Table D2.0-5
Mitigation: Water Quality	Dissolved Oxygen Enhancement Feasibility Study			1			$0.0		$0.0	
Mitigation: Water Quality	Management of Keno Reservoir to Improve Water Quality			1	1		$0.0	700.0	$11,409.6	FWS Staff
Decommissioning	Decommission the East Side development		1		1	393	$329.0		$0.0	PC 7/21/04 Response to Deficiency Notice, page 3
Decommissioning	Decommission the West Side development		1		1	451	$377.5		$0.0	PC 7/21/04 Response to Deficiency Notice, page 3